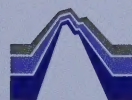


AR77



PARAMOUNT
RESOURCES LTD.
ANNUAL REPORT
2002



Paramount Resources Ltd. is a Canadian energy company with 78 percent natural gas leverage. The Company explores for, develops, processes, transports and markets petroleum and natural gas. Paramount has core areas of production in Central Alberta; Kaybob and Sturgeon Lake/Mirage, Northwest Alberta/Cameron Hills NWT, the Liard Basin in the Northwest Territories/Northeast British Columbia, and Southern Alberta which includes production from Saskatchewan, California, Montana and North Dakota as well.

The Company has diversified from its traditional shallow gas exploration and development, which was its niche for many years. These relatively mature assets have been successfully moved to an income generating trust. The Company grew in 2002 with the acquisition of Summit Resources Limited. These Summit assets complement the Company's central Alberta core areas and will enable Paramount to achieve a higher rate of growth through improved control of assets, infrastructure efficiencies and cost savings.

Paramount has a strong portfolio of exploration prospects in Alberta as well as the Northwest Territories, Northeastern British Columbia, Saskatchewan, Montana and North Dakota.

Paramount has adapted to a multitude of operating climates over the past 24 years and continues to record sustainable growth.

2002 Financial Highlights

REFERENCE

	Year Ended December 31		
	2002	2001	% Change
(\$ thousands except per share amounts and where stated otherwise)			
Financial			
Gross revenue	473,942	528,373	(10%)
Cash flow			
From operations	259,916	303,937	(14%)
Per share – basic	4.37	5.11	(14%)
– diluted	4.36	5.11	(15%)
Earnings			
Net earnings	10,307	118,902	(91%)
Per share – basic	0.17	2.00	(92%)
– diluted	0.16	2.00	(92%)
Capital expenditures			
Exploration and development	217,196	272,323	(20%)
Summit acquisition	449,648	–	–
Other	(145,580)	(11,139)	1,207%
Net capital expenditures	521,264	261,184	100%
Total	1,536,384	1,176,323	31%
Net debt	555,243	290,698	91%
Shareholders' equity	546,105	535,384	2%
Weighted average common shares outstanding (thousands)	59,458	59,454	–
Common Shares Outstanding at Year-end (thousands)	59,459	59,453	–
Common Shares Outstanding at February 28, 2003 (thousands)	60,169		
Operating			
Production			
Natural gas (MMcf/d)	241.4	225.0	7%
Crude oil and liquids (Bbl/d)	5,663	2,165	162%
Total Production (MMcfeg/d) @ 10:1	298.0	246.7	21%
Total Production (BOE/d) @ 6:1	45,898	39,665	16%
Average Prices			
Natural gas (pre-hedge) (\$/Mcf)	3.53	5.93	(40%)
Natural gas (\$/Mcf)	4.08	6.12	(33%)
Crude oil and liquids (\$/Bbl)	34.64	35.48	(2%)
Reserves (proved and probable)			
Natural gas (Bcf)	618.6	563.7	10%
Crude oil and liquids (MBbl)	22,846	7,967	187%
Estimated present worth value before tax discounted @ 10%			
Proved (\$ millions)	983	696	41%
Proved and probable (\$ millions)	1,258	870	45%
Land (thousands of acres)			
Total net land holdings	5,077	4,984	2%
Net undeveloped land holdings	3,545	3,765	(6%)
Drilling Activity (gross)			
Gas	114	167	(32%)
Oil	9	12	(25%)
Other	1	1	–
D&A	11	16	(31%)
Total wells	135	196	(31%)
Success rate	92%	92%	–

Review of Operations
pg. II

AIF
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PAGE I



Production increased

16%

to average
45,898 BOE/d

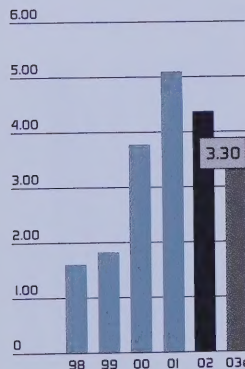
JIM RIDDELL
PRESIDENT &
CHIEF OPERATING
OFFICER

CLAY RIDDELL
CHAIRMAN OF
THE BOARD &
CHIEF EXECUTIVE
OFFICER

Letter to Shareholders

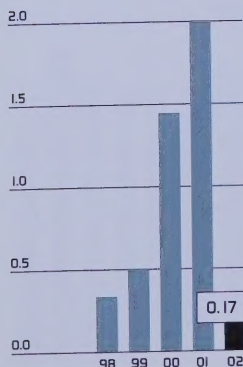
RESULTS

Cash Flow per Share
(\$/share)



RESULTS

Earnings per Share
(\$/share)



The year 2002 will be remembered as a very exciting year in the history of Paramount Resources Ltd. In late 2001, and the early part of 2002, Paramount began evaluating a plan to move its Northeast Alberta properties into a trust structure to maximize value to the shareholder by means of a better tax treatment of the cash flow being generated from these properties as well as a superior valuation of these assets in the public markets. By the end of April, the internal evaluation process was coming to an end and the discussion to move ahead with the Paramount Energy Trust was all but finalized when the Corporate acquisition of Summit Resources Limited ("Summit") was secured.

This acquisition is unique in that the asset fit with Paramount's existing assets after dividend of the Northeast Alberta properties is exceptional and the majority of the equity of Summit was controlled by one group. A favorable purchase price was negotiated and both deals were announced on the same day, May 12, 2002. The Summit acquisition added 13,531 BOE/d on a 6:1 basis comprised of 52 MMcf/d of natural gas and 4,812 Bbl/d of oil and natural gas liquids production. Reserves of Summit as at December 31, 2001 were 115.6 Bcf of proven natural gas reserves (150.3 Bcf proven plus probable) and 10.5 MMBbl of proven oil and natural gas liquids reserves (14.2 MMBbl proven plus probable). The only hitch in the whole plan was the period of time when the equity from the rights issue from the Trust could be raised to pay Paramount Resources Ltd. for the Northeast Alberta assets and allow it to fully finance the Summit acquisition.

Paramount was paid its \$47.1 million by the Government of Alberta relating to the shut-in of 22 MMcf/d of net gas production in May 2000. Paramount also successfully sold its investment in Peyto Exploration and Development Corp. for \$45.0 million which was a large portion of its investments in other energy related activities. This \$92 million plus the \$150 million of equity from the rights issue in Paramount Energy Trust totaled \$242 million which was almost the exact amount Paramount paid for the equity of Summit Resources Limited. Paramount also assumed \$81 million of net debt owed by Summit Resources Limited.

The process to dividend out the Paramount Energy Trust to the shareholders, albeit slower than originally anticipated, resulted in the final approval by all Securities Commissions in Canada and the Securities and Exchange Commissioner in the United States being granted February 2, 2003. Paramount Energy Trust was listed to begin trading February 7, 2003 on the Toronto Stock Exchange; the subsequent rights offering closed March 10, 2003, and the closing of the sale of the additional assets occurred on March 11, 2003. Paramount transferred to Paramount Energy Trust approximately 100 MMcf/d of natural gas production which equates to 16,667 BOE/d on a 6:1 basis effective July 1, 2002. Reserves associated with the production are 161 Bcf of proven natural gas reserves (199 Bcf proven plus probable).

RELATED INFORMATION

www.paramountres.com

PAGE 3

Letter to Shareholders (continued)

At this point all the transactions necessary to complete the spinout of the Paramount Energy Trust have occurred and the two entities now trade separately and operate at arms length.

With this transaction, Paramount shareholders hold an investment in both an exciting intermediate sized exploration and development company and, as well, an income generating trust with growth prospects of its own.

Throughout 2002, the environment for the Canadian Energy Industry has improved dramatically with commodity prices at the time of writing at relatively high levels. A very cold winter in the consuming regions of North America as well as sharply declining supply have combined to see record rates of withdrawal from storage through the winter of 2002/2003 and industry anticipating year end storage levels to read their lowest since 1996. Without a significant demand response, the 2003/2004 upcoming winter may see even further upward pressure on natural gas pricing.

Crude oil markets have also seen strong upward movement as a result of striking oil workers in Venezuela reducing supply to North America, a very cold winter, and political unrest in the Middle East with the war with Iraq overhanging the world oil markets. The longer-term fundamentals are not as clear for crude oil markets as many of the influences on pricing could change very quickly.

Paramount's 2003 capital program is approximately \$150 million and is designed to modestly increase production and more importantly, see cash flow out outpace capital expenditures by roughly \$50 million which would go directly to debt reduction and strengthening of Paramount's balance sheet. The largest development program to be undertaken is the tie-in of the Cameron Hills Oil project. Five oil wells are currently being tied in to a newly constructed oil battery at Cameron Hills which is scheduled to commence production in April 2003. Part of the tie in project involves the construction of a new 72 kilometer oil sales line and compressor station to deliver the oil to market.

The most significant exploration prospect being tested is at Colville Lake in the Northwest Territories. Paramount is drilling both the Nogha C-49 well and the M-17 well. The Colville Lake project area lies at the Arctic Circle in the Mackenzie Valley and as such is not only dependent on drilling success, but also the development of infrastructure to the area. The Company has pursued development of many other projects beyond the pipelines in its history and this has proved to be a very successful strategy.

REFERENCE

Review of Operations
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Review of Operations
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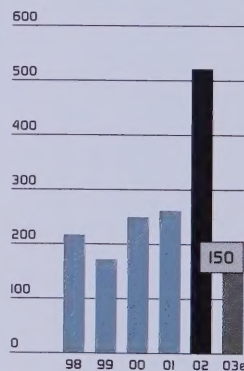
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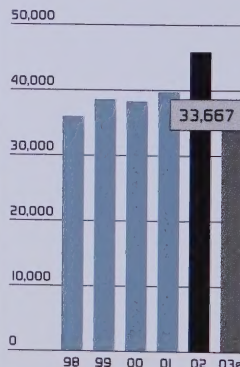
RESULTS

Net Capital Expenditures
(\$ millions)



RESULTS

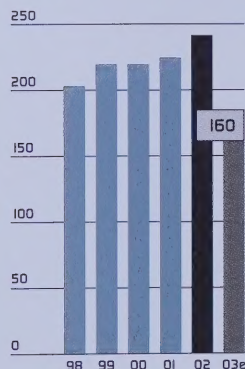
Production
(BOE/d@5:1)



Letter to Shareholders (continued)

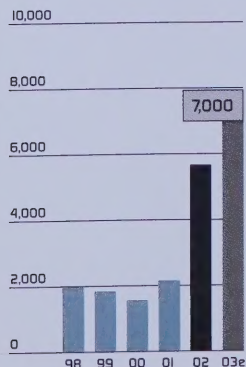
RESULTS

Natural Gas Sales
(MMc/d)



RESULTS

Crude Oil and Liquids Sales
(Bbl/d)



To date Paramount has drilled, cased and successfully completed the first two wells in the Colville Lake play area. Plans to further establish additional reserves by testing additional defined structures in the next 2003/2004 drilling season, are being evaluated.

A realistic time frame to expect production from the Colville Lake area, assuming threshold reserves are established, would be in the spring of 2007. While this may look far out today, longtime Paramount shareholders can reflect that the initial Liege discovery was made in the winter of 1976; production was not achieved until six years later in 1982. Patience was rewarded as this was the foundation on which Paramount was built.

In the fall of 2002, Paramount embarked on a property rationalization program to divest of minor non-core properties primarily acquired through the Summit acquisition. The original goal of this program was to generate approximately \$30 million in net proceeds. The Company now anticipates proceeds of \$70-90 million which is well in excess of the goal.

2003 will be a year where Paramount consolidates its producing property portfolio as well as its exploration portfolio and at the same time repositions the balance sheet to be in a position to aggressively move forward. We look forward to resumed and continued growth in the Kaybob and Sturgeon Lake/Mirage areas of Central Alberta, Northwest Alberta, NE B.C./Liard NWT Core areas, and the new Southern Alberta/Southeast Saskatchewan/Montana/North Dakota Core area.

It is a testament to the quality and perseverance of the staff of Paramount Resources that the Company emerges from the last 12 months of change with such optimism. To achieve the Corporate acquisition of Summit Resources Limited, to create a new Energy Income Trust within the top 10 in size in Canada, to consummate the Surmont compensation process, and to also successfully market three separate property disposition packages all in the last 12 months is truly remarkable and shareholders should be proud of the exceptional efforts. Paramount has delivered incremental shareholder value through these events and emerges reinvigorated for growth going forward.

James H. T. Riddell
President and
Chief Operating Officer

RELATED INFORMATION

www.paramountres.com

PAGE 5

**NORTHEAST
BRITISH COLUMBIA/
LIARD CORE AREA**

Production:
12.3 MMcf/d
15 Bbl/d

NON-CORE AREAS

Production:
1.9 MMcf/d
237 Bbl/d

**NORTHWEST
ALBERTA
CORE AREA**

Production:
30.4 MMcf/d
35 Bbl/d

**STURGEON LAKE/
MIRAGE CORE AREAS**

Production:
7.0 MMcf/d
1,353 Bbl/d

**NORTHEAST
ALBERTA**

Production:
96.9 MMcf/d

KAYBOB CORE AREA

Production:
87.5 MMcf/d
2,291 Bbl/d

**SOUTHERN ALBERTA/
SOUTHEAST SASKATCHEWAN/
MONTANA/NORTH DAKOTA**

Production:
5.4 MMcf/d
1,732 Bbl/d

BC

AB

SK

WA

ID

CANADA

USA

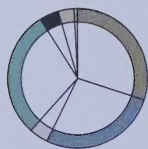
MT

NO

Core Producing Areas

RESULTS

Drilling Distribution
(wells)



- ☐ Northeast Alberta
- ☐ Kaybob
- ☐ Sturgeon Lake/Mirage
- ☐ Northwest Alberta
- ☐ Southern Alberta/Southeast Saskatchewan/Montana/North Dakota
- ☐ Northeast BC/NWT
- ☐ Exploration

REFERENCE

KAYBOB

Production in the Kaybob Operating Unit averaged 87.5 MMcf/d of natural gas and 2,291 Bbl/d of crude oil and natural gas liquids for 2002, up from the 2001 averages of 68.4 MMcf/d and 1,855 Bbl/d. Year-end exit rates for the area were 90.3 MMcf/d and 2,383 Bbl/d; rates are expected to stay relatively flat for 2003, averaging 90 MMcf/d and 2,200 Bbl/d for the year.

Drilling activity in 2002 included 37 (29.8 net) wells resulting in 24.7 net natural gas wells, 2.6 net oil wells and 2.5 net dry and abandoned wells. This compares to 61 (51.6 net) wells in 2001. Anticipated activity for 2003 is expected to be similar to 2002 with 31 wells being drilled. Results from numerous workovers and recompletions in 2002 on shut-in and suspended wells, have also contributed to the increase in production in the Kaybob area.

Paramount tries to maintain control of its production by operating the wells and production facilities that processes the natural gas and liquids. There are currently four company-operated gas plants in the area that process 71 percent of Paramount's natural gas. Efforts are underway to increase the amount of operated natural gas and liquids production, which should result in lower operating costs.

STURGEON LAKE / MIRAGE

This is a new corporate operating area near Valleyview (Sturgeon Lake / Sunset fields) and Grande Prairie (Mirage field). As of July 1, 2002, Paramount acquired Burlington and Summit's interests in the Sturgeon Lake area and took over the operation of the Sturgeon Lake South oil treating and sour gas plant at 2-2-69-21 W5. The plant currently processes 3,000 Bbl/d of oil and 5 MMcf/d of gas. Annual average rates for the area were 7.0 MMcf/d and 1,353 Bbl/d with exit rates of 11.6 MMcf/d and 2,230 Bbl/d. There were two wells drilled (0.7 net) and five recompletions done (4.0 net) in 2002 in the shallow Dunvegan and deeper Montney and Gething zones.

For 2003 the Company expects to drill 18 wells (12.7 net) and recomplete an additional 11 wells (9 net) in the shallow Dunvegan, Cretaceous and deeper Leduc/Wabamun formations. The forecasted average production rates are 15 MMcf/d and 2,200 Bbl/d.

NORTHWEST ALBERTA

The Northwest Alberta region covers the extreme northwest corner of Alberta, extending into the Cameron Hills in the Northwest Territories. Targeted hydrocarbon bearing zones in the region start with Pleistocene-aged sands and gravels located at depths of 30 meters through Cretaceous-aged Bluesky/Gething sands, Mississippian carbonates, ending with middle Devonian carbonates at depths of 1,600 meters. Production facility design and operation in the region accommodates a range of raw production including low-pressure sweet natural gas and high-pressure sour oil and natural gas.

In Northwest Alberta and Cameron Hills NWT, Paramount participated in the drilling of 49 wells, (38.6 net) in the calendar year 2002. The vast majority of field activities relating to seismic acquisition, drilling, and construction occurred in the first quarter due to the restricted seasonal access of the area. Natural gas sales averaged 30.4 MMcf/d in 2002 from the Northwest Alberta region; crude oil and natural gas liquids averaged 35 Bbl/d.

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RELATED INFORMATION

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Core Producing Areas

REFERENCE

NORTHWEST ALBERTA (CONTINUED)

The highlight of 2002 was the tie-in of six gas wells located in Cameron Hills, NWT to processing facilities situated at Bistcho Lake in Alberta. Paramount operates and owns 60 percent of the 50 MMcf/d Bistcho Lake processing facility.

Paramount will be participating in 21 (19.2 net) wells in the Northwest Alberta region in the first quarter of 2003. A 77 square kilometer 3D seismic program conducted at Cameron Hills in the first quarter of 2003 will be used to identify future oil and natural gas drilling targets. The big news in 2003 for the region will be bringing five oil wells on production in Cameron Hills. The oil will flow from Cameron Hills through existing pipe to the Bistcho Lake facility and then on to Zama Lake and into the Rainbow pipeline system through a newly Paramount-constructed oil line.

LIARD BASIN – NORTHEAST BRITISH COLUMBIA/NORTHWEST TERRITORIES

The Liard Basin continues to be an active exploration and production area for Paramount. As a result of several 3D seismic programs shot last year, the 2002/2003 winter drilling program is focused primarily on deep Devonian play concepts. Along the Liard fault trend, Paramount will participate in two to three non-operated Devonian tests. Two of these locations are targeting potential new pools while the third is a delineation well located at the north end of the Chevron Liard Nahanni pool. At Arrowhead, along the Bovie fault trend, a farmout agreement with Anadarko includes the drilling of four Devonian tests as well as three shallower Chinkeh locations. Paramount also plans to drill one to two Mattson locations northeast of the town of Fort Liard.

Average production from the Liard/Northeast British Columbia Core Area increased by 32 percent to 12.3 MMcf/d from 2001 to 2002 mainly due to the addition of the Clarke Lake property as part of the Summit acquisition and the tie-in of two wells in the Maxhamish area, a-96-J and b-43-K, in the first quarter of 2002.

A Maxhamish well, b-83-K, will be tied-in during the first quarter of 2003 and the existing production and reserve recovery will continue to be optimized by installing booster compression and liquid lifting systems.

SOUTHERN ALBERTA/SASKATCHEWAN/MONTANA/NORTH DAKOTA

Paramount's Southern Operating Unit is a new operating area for the Company with the majority of the properties coming from the acquisition of Summit Resources Limited.

Geographically the Unit is extensive with operations in Canada extending south from township 49, south of Edmonton, in Alberta and in the Southeast corner of Saskatchewan. In the USA, operations are located in north-central and northeastern Montana and in western North Dakota. The Southern Operating Unit has the advantage of year-round access to all of its production operations.

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Core Producing Areas

The Southern Operating Unit began a process of consolidation and focus in the fourth quarter of 2002. This process will see the Southern Operating Unit divest of smaller interest and non-operated/non-core properties and pursue the growth of fewer, higher interest core properties. This process will carry over to the first quarter of 2003 and see the Southern Operating Area move from having in excess of 75 individual properties down to seven or eight core properties.

In Southern Alberta core operations areas include Sylvan Lake, Chain/Craigmyle, Enchant and Retlaw/Long Coulee. At Sylvan Lake current production is from the Cretaceous Belly River, Viking and lower Mannville and the Mississippian Pekisko. Production is split 75/25 natural gas and oil. In Chain/Craigmyle, Paramount produces oil from the Mississippian Banff and natural gas from the Cretaceous Belly River, Viking and Mannville. Production is primarily natural gas with the majority processed at the 100 percent Paramount owned 6-11-13-18W4 gas plant. At Enchant, Paramount produces oil primarily from the Jurassic Sawtooth with some minor oil and natural gas produced from the Devonian Arcs. Most of the oil is produced through the 14-32-12-15W4 battery, 100 percent owned by Paramount. Solution gas is conserved and is processed through the Anadarko operated Hays gas plant. At Retlaw/Long Coulee Paramount produces natural gas from various Cretaceous Mannville intervals.

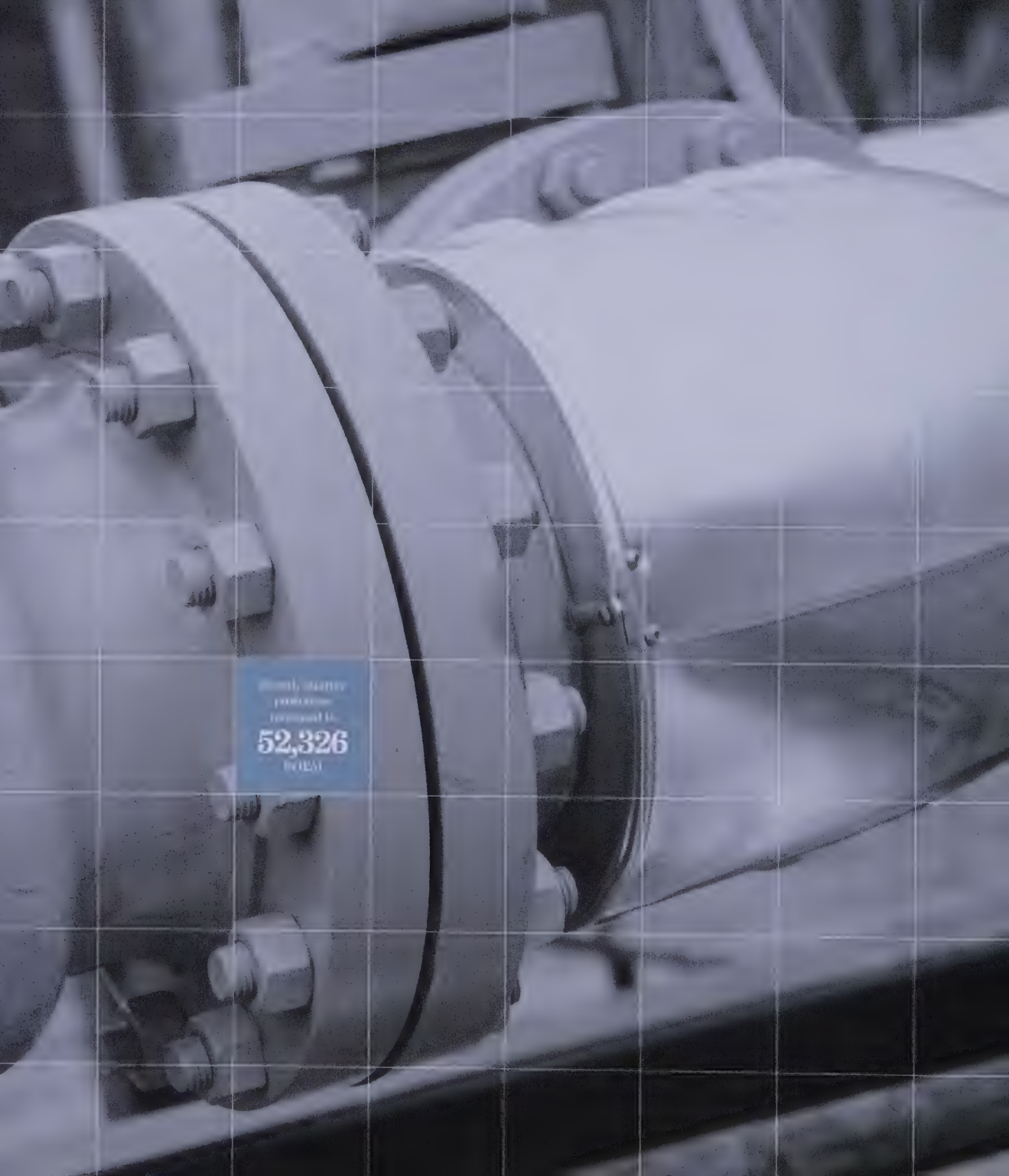
In southeastern Saskatchewan, Paramount produces oil primarily from the Mississippian Midale. Major producing properties are at Neptune, Tatagwa, Loughheed, Weyburn and Benson. All of these properties have centralized battery and water handling facilities.

In north-central Montana, Paramount's Rabbit Hills property produces oil from the Jurassic Bowes. Part of Paramount's production in Rabbit Hills has recently received regulatory approval for unitization that would allow for centralized facilities and proceeding with a secondary recovery scheme. In northeastern Montana Paramount produces oil at several properties from the Ordovician Red River, Devonian Nisku and Mississippian Bakken.

In North Dakota, the majority of Paramount's oil production comes from Beaver Creek/Roosevelt, Knutson and Hilina/Versippi. Beaver Creek/Roosevelt has year-round accessibility. Oil is produced from several formations in these fields with the Ordovician Red River being the most prolific. The Mississippian Bakken has also contributed considerable production, along with the Devonian Duperow formation. Other established pay intervals are the Devonian Nisku, Silurian Stonewall and Interlake zones. These productive intervals range in depth from 10,500 to 12,500 feet. Knutson Field is located in Billings and Golden Valley counties. Light sweet oil (37° API) production is from the Mississippian Mission Canyon formation at a depth of about 9,100 feet. The northern extent of the Knutson Mission Canyon pool was unitized in 2001. Paramount owns a 27.8 percent non-operating interest in the Hilina Lodgepole Unit and a 61 percent non-operating interest in the Versippi Lodgepole Unit, both located in Stark County, North Dakota. The fields produce light sweet crude (41° API) and the natural gas is conserved. The Lower Mississippian Lodgepole is a carbonate buildup from either mud mounds or lithified reefal development.

REFERENCE

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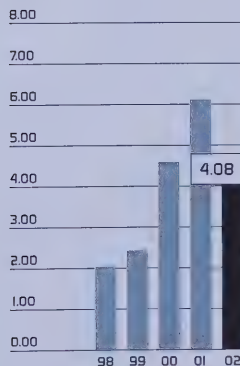


Global, reliable
performance.
Forward to
52,326
TWh.

Review of Operations

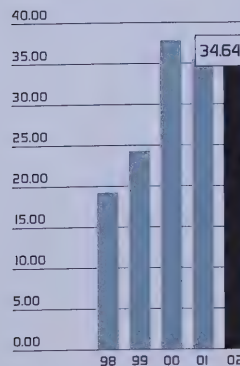
RESULTS

Natural Gas Price
(\$/Mcf)



RESULTS

Crude Oil and Liquids Price
(\$/Bbl)



PRODUCTION

Paramount increased total production in 2002 by 21 percent to 298 MMcf/d. On a 6:1 basis, total production increased 16 percent from 39,665 BOE/d in 2001 to 45,898 BOE/d in 2002. Natural gas production in 2002 increased 7 percent to 241.4 MMcf/d from 225.0 MMcf/d in 2001. Crude oil and natural gas liquids production increased 162 percent from 2,165 Bbl/d in 2001 to 5,663 Bbl/d in 2002. The fourth quarter was particularly strong as year over year results increased on a 6:1 basis, from 38,365 BOE/d in 2001 to 52,326 BOE/d in 2002. Production included volumes from the Northeast Alberta core areas which have since been transferred to the Paramount Energy Trust; these volumes for the second half of 2002 approximated 94 MMcf/d of natural gas or 47 MMcf/d annualized for 2002.

Natural Gas Production (MMcf/d)	2003e	2002	2001
Northeast Alberta (East Side)	-	38.8	41.6
Northeast Alberta (West Side)	-	58.1	67.1
Kaybob	90	87.5	68.4
Sturgeon Lake	15	7.0	-
Northwest Alberta	30	30.4	29.2
Liard	15	12.3	9.3
Southern Alberta/Saskatchewan/Montana/North Dakota	10	5.4	-
Other	-	1.9	9.4
Total	160	241.4	225.0

AIF
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Crude Oil & NGL Production (Bbl/d)	2003e	2002	2001
Kaybob	2,200	2,291	1,855
Sturgeon Lake	2,200	1,353	-
Northwest Alberta	1,000	35	-
Liard	-	15	21
Southern Alberta/Saskatchewan/Montana/North Dakota	1,600	1,732	130
Other	-	237	159
Total	7,000	5,663	2,165

MD&A
pg. 28

PROFITABILITY

Paramount endeavors to effect all factors which are in our control and influence to the extent of our ability, those which do not. Production volumes, operating costs, general and administrative costs, as well as capital expenditures fall within our control. Opportunities are also pursued to maximize commodity prices and minimize royalty rates.

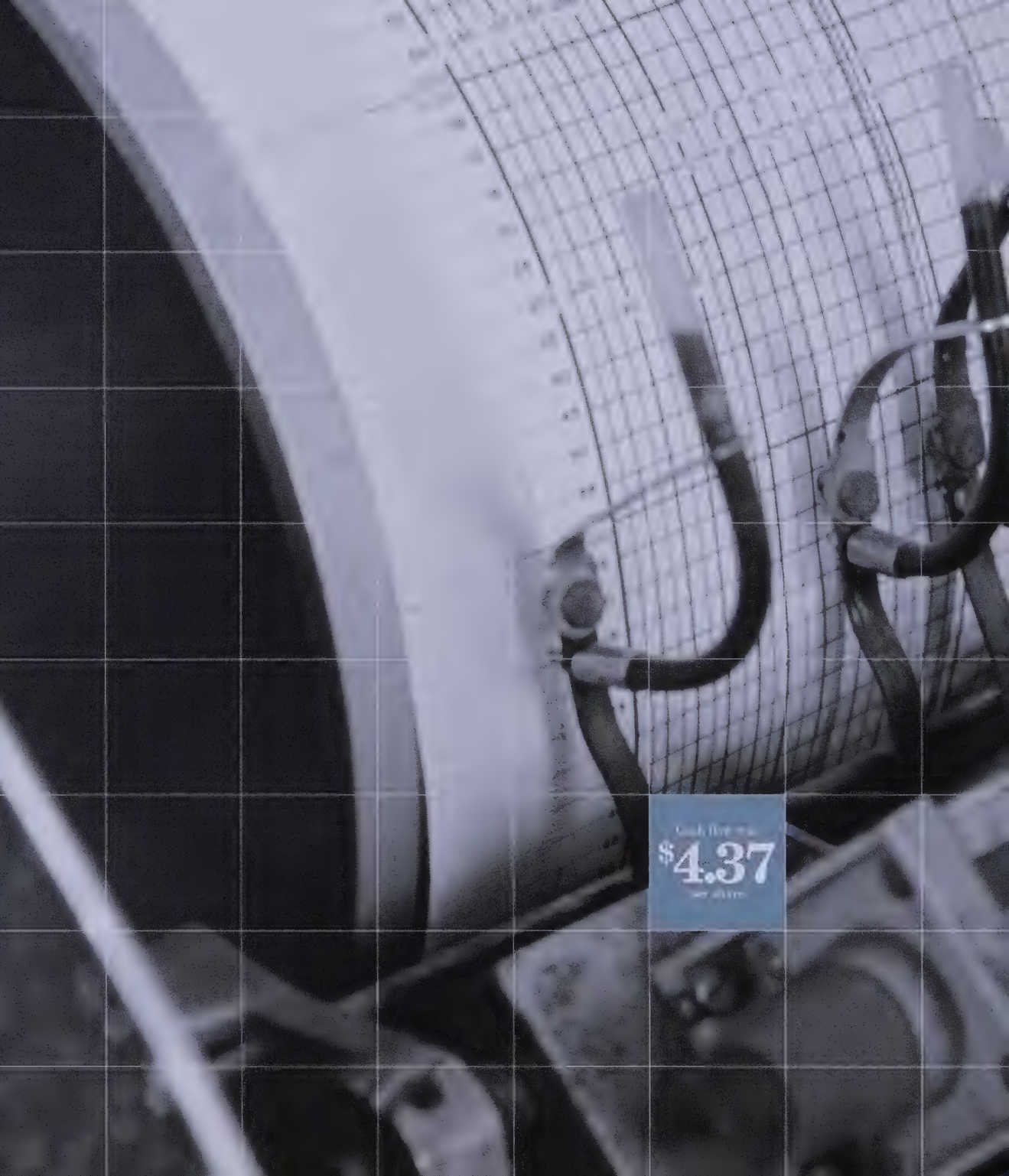
Commodity Prices

Natural gas prices in 2002 were enhanced through hedging activities which increased the realized natural gas price from \$3.53/Mcf to \$4.08/Mcf, a 16 percent increase. This increased price, which directly increases profitability, showed a 33 percent decrease from 2001 levels of \$6.12/Mcf. Crude oil and natural gas liquids prices for 2002 averaged \$34.64/Bbl as compared to \$35.48 Bbl in 2001; a modest

RELATED INFORMATION

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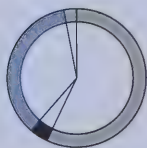


Each 1000 lbs.
\$4.37
per 1000 lbs.

Review of Operations

RESULTS

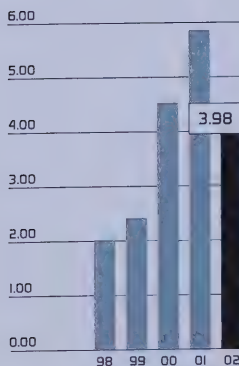
2002 Exploration and Development Expenditures



- Drilling and Completion
- Geological and Geophysical
- Plant, Gathering and Equipment
- Land Purchases

RESULTS

Revenue (\$/Mcfq)



Commodity Prices (continued)

decrease of 2 percent. Fourth quarter 2002 pricing increased substantially with natural gas 50 percent higher at \$4.54/Mcf as compared to \$3.03/Mcf in the fourth quarter of 2001; crude oil and natural gas liquids pricing was 27 percent higher at \$35.27/Bbl as compared to \$27.81/Bbl in the fourth quarter of 2001.

Operating Costs

Operating costs on a unit-of-production basis increased 16 percent from \$0.68/Mcf in 2001 to \$0.79/Mcf in 2002. Paramount expects costs to decrease on a per unit basis and in absolute terms in 2002 with the disposition of assets to Paramount Energy Trust and as a result of efficiencies from operational synergies gained from the acquisition of Summit.

Royalties

Royalties decreased in 2002 as a result of lower commodity prices. As a percentage of revenue the royalty rate reflects lower commodity prices and gains attributed to commodity hedges.

General and Administrative Costs

General and administrative costs increased in 2002 as a direct result of higher overhead expenses associated with the acquisition of Summit and setting up of Paramount Energy Trust. These one-time costs which included staffing and relocation costs will not recur. Lower capital expenditures in 2002 contributed to lower overhead recoveries which increased net general and administrative costs. On a unit-of-production basis, costs increased from \$0.14/Mcfq to \$0.15/Mcfq.

Cash Flow

Cash flow in 2002 decreased 15 percent to \$259.9 million principally as a result of lower commodity prices. Fourth quarter cash flow increased 29 percent to \$61.8 million as compared to the same period in 2001 as a result of higher commodity prices and higher production levels.

Cash Flow Reconciliation

Volume (MMcfq) ⁽¹⁾	2002		2001	
	108,781		90,027	
	(\$/Million)	(\$/Mcfq)	(\$/Million)	(\$/Mcfq)
Gross revenue ⁽²⁾	\$ 433.1	\$ 3.98	\$ 525.7	\$ 5.84
Gain on sale of investments	40.8	0.38	2.7	0.03
Royalties (net of ARTC)	(74.4)	(0.68)	(99.7)	(1.11)
Operating costs	(86.1)	(0.79)	(61.1)	(0.68)
Netback	313.4	2.89	367.6	4.08
G&A	(16.2)	(0.15)	(12.4)	(0.14)
Non-cash g&a	0.3	0.00	—	—
Interest on long-term debt	(23.9)	(0.22)	(19.3)	(0.21)
Lease rentals	(4.6)	(0.04)	(4.3)	(0.05)
Large corporation/current taxes	(9.1)	(0.08)	(27.7)	(0.31)
Cash flow	\$ 259.9	\$ 2.40	\$ 303.9	\$ 3.37
Weighted average shares (millions)	59.5		59.5	
Cash flow per basic share	\$ 4.37		\$ 5.11	

(1) Barrels of oil converted to gas sales on the basis of 1 barrel = 10 Mcf.

(2) Revenue includes petroleum and natural gas revenue and other.

REFERENCE

MD&A
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MD&A
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RELATED INFORMATION

www.paramountres.com



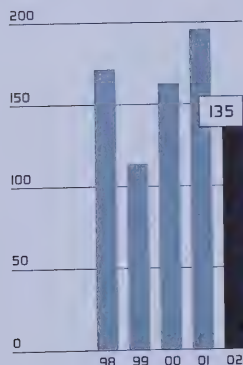
ENVIRONMENTAL
WATER LIMITED WITH A
MORTGAGE RATE OF

92%

Review of Operations

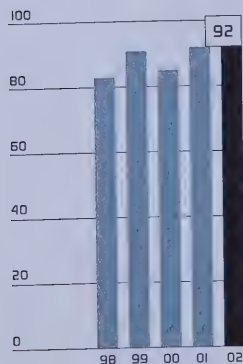
RESULTS

Wells Drilled
(gross)



RESULTS

Drilling Success Rate
(%)



NET CAPITAL EXPENDITURES

Net capital expenditures in 2002 doubled to \$521.3 million reflecting the corporate acquisition of Summit for approximately \$335 million. Conventional exploration and production expenditures of \$217.2 million in 2002 were comprised of \$6.4 million in land acquisitions, \$9.3 million in geological and geographical expenditures, \$124.1 million in drilling expenditures and \$77.4 million in facilities and production equipment. An additional \$23.6 million was spent on acquisition net of dispositions in 2002. Conventional exploration and development expenditures were reduced 20 percent in 2002 from prior year levels.

LAND

(thousand acres)

	2002			2001		
	Gross	Net	Average working interest	Gross	Net	Average working interest
Land assigned reserves	2,169	1,532	71 %	1,675	1,218	73 %
Undeveloped land	5,506	3,545	64 %	4,901	3,765	77 %
Total	7,675	5,077		6,576	4,983	
Fair market value of undeveloped land (\$ millions)	\$ 117.3			\$ 100.9		

DRILLING

Paramount participated in the drilling of 135 (99.4 net) wells with a success rate of 92 percent. A total of 114 (83.7 net) natural gas wells, 9 (6.7 net) oil wells, 1 (1.0 net) service well, and 11 (8.0 net) dry holes were drilled. A total of 41 (31.3 net) wells were drilled in Northeast Alberta, 42 (33.5 net) wells were drilled in Kaybob Central Alberta area; 40 (30.3 net) wells were drilled in the Northwest Alberta Core Area, 6 (0.8 net) wells were drilled in the Southern area; and 6 (3.6 net) wells were drilled in the Northwest Territories.

Drilling Results

	2002		2001	
	Gross	Net	Gross	Net
Exploratory				
Gas	38	27.4	66	52.5
Oil	4	3.6	5	4.3
Service/standing	-	-	1	0.5
D & A	4	4.0	12	7.4
Total exploratory	46	35.0	84	64.7
Success rate (gross)	91%		86%	
Development				
Gas	76	56.3	101	84.4
Oil	5	3.1	7	6.1
Service/standing	1	1.0	-	-
D & A	7	4.0	4	3.5
Total development	89	64.4	112	94.0
Success rate (gross)	92%		96%	
Total all well categories	135	99.4	196	158.7
Success rate (gross)	92%		92%	

RELATED INFORMATION

www.paramountres.com

REFERENCE

MOSA
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PAGE 15

125th Anniversary

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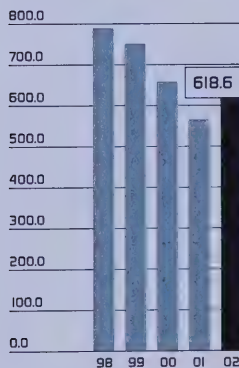
1870-2015

Review of Operations

RESULTS

Natural Gas Reserves

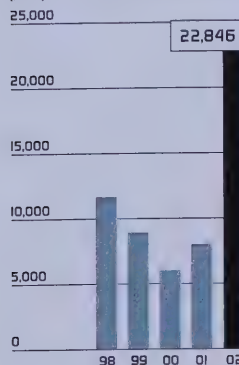
Proved & Probable (gross before royalties) (Bcf)



RESULTS

Crude Oil and NGL Reserves

Proved and Probable (gross before royalties) (MBbl)



RESERVES

Paramount's year-end reserve balance for proved plus probable reserves increased 24 percent to total 125 million BOE at January 1, 2003, as compared to 102 million BOE at January 1, 2002. This increased reserve balance equates to Paramount replacing its production in 2002 by 243 percent. Natural gas reserves increased 10 percent to 618.6 Bcf. Crude oil reserves increased 267 percent to 18.2 million barrels; and natural gas liquids reserves increased from 3.0 million barrels to 4.6 million barrels, or 53 percent all on a proved plus probable basis. Proved reserves increased 16 percent from 79.3 million BOE to 92 million BOE; this included a reduction of 6.5 million BOE as the gas reserves shut-in at Surmont were removed from the proven category. The acquisition of Summit increased reserves by 91 Bcf of gas and 11.9 million barrels of crude oil and natural gas liquids; exploration and development expenditures increased reserves by 39 Bcf and 1.4 million barrels; additional acquisitions added 2.7 million BOE and total reserves added an additional 3.2 million BOE all on a proved plus probable basis. The subsequent transfer of the Northeast Alberta properties to the Paramount Energy Trust will reduce Paramount's reserves by 164 Bcf proved or 203.6 Bcf proved plus probable.

Natural Gas Reserves

	2002		2001	
	Bcf	% of Total	Bcf	% of Total
Proved: producing	344.2	55	298.9	53
non-producing, undeveloped	102.3	17	138.8	25
Total Proved	446.5	72	437.7	78
Probable additional	172.1	28	126.0	22
Total Proved and Probable	618.6	100	563.7	100

Crude Oil and Natural Gas Liquids Reserves

	2002		2001	
	MBbl	% of Total	MBbl	% of Total
Proved: producing	14,677	64	5,063	64
non-producing, undeveloped	2,868	13	1,276	16
Total Proved	17,545	77	6,339	80
Probable Additional	5,301	23	1,628	20
Total Proved and Probable	22,846	100	7,967	100

REFERENCE

AIF
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RELATED INFORMATION

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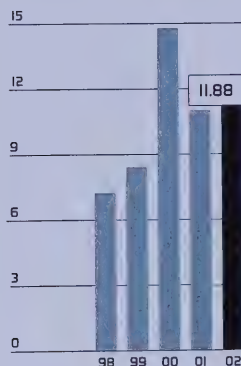


Midwest Energy
\$11.88
per barrel

Review of Operations

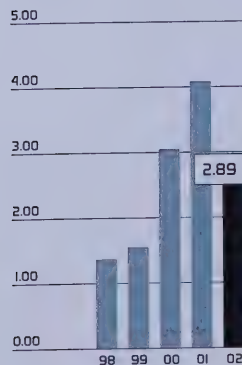
RESULTS

Net Appraised Asset Value
(\$/share)



RESULTS

Operating Netback
(\$/Mcfeq)



NET ASSET VALUE

Paramount's net asset value per share at December 31, 2002 remained relatively unchanged from the prior year.

Net (Appraised) Asset Value (millions of dollars as at December 31)	2002	2001
Present value of reserves, before royalties ⁽¹⁾	\$ 1,120.3	\$ 859.7
Market value of short-term investments	14.2	29.6
Alberta Royalty Tax Credit (ARTC) ⁽¹⁾⁽²⁾	3.4	3.4
Fair market value of undeveloped land	117.3	100.9
Other	20.5	—
Subtotal	1,275.7	993.6
Working capital (deficiency)	(30.1)	13.8
Total assets	1,245.6	1,007.4
Bank loans	(498.2)	(314.2)
Shareholder loan	(33.0)	—
Drilling rig indebtedness	(1.4)	(2.4)
Mortgage	(6.7)	—
Net (appraised) asset value	\$ 706.3	\$ 690.8
Net (appraised) asset value per basic common share ⁽³⁾	\$ 11.88	\$ 11.60

(1) @ 10 percent discount, proven plus half probable.

(2) ARTC: only on proved reserves.

(3) Outstanding shares: 2002 – 59,458,600 (2001 – 59,453,600).

Notes to Net Asset Value

- Reserve values were determined by McDaniel and Associates Consultants Ltd. ("McDaniel") and Sproule and Associates ("Sproule") as at January 1, 2003, using the forward pricing assumptions in effect by the respective firms at that date.
- No value has been assigned to tangible assets other than those associated with proved producing reserves.
- Paramount's hedging activities, which extend past January 1, 2003, have not been valued by either McDaniel or Sproule.
- Bank indebtedness will be reduced by \$250 million upon receipt of proceeds from Paramount Energy Trust resulting from the closing of the transfer of assets.
- Reserves and the value associated with the transfer of the Northeast Alberta assets to Paramount Energy Trust will be reflected at the date of closing.

REFERENCE

Financial Statements
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RELATED INFORMATION

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2003
Gas Drilling

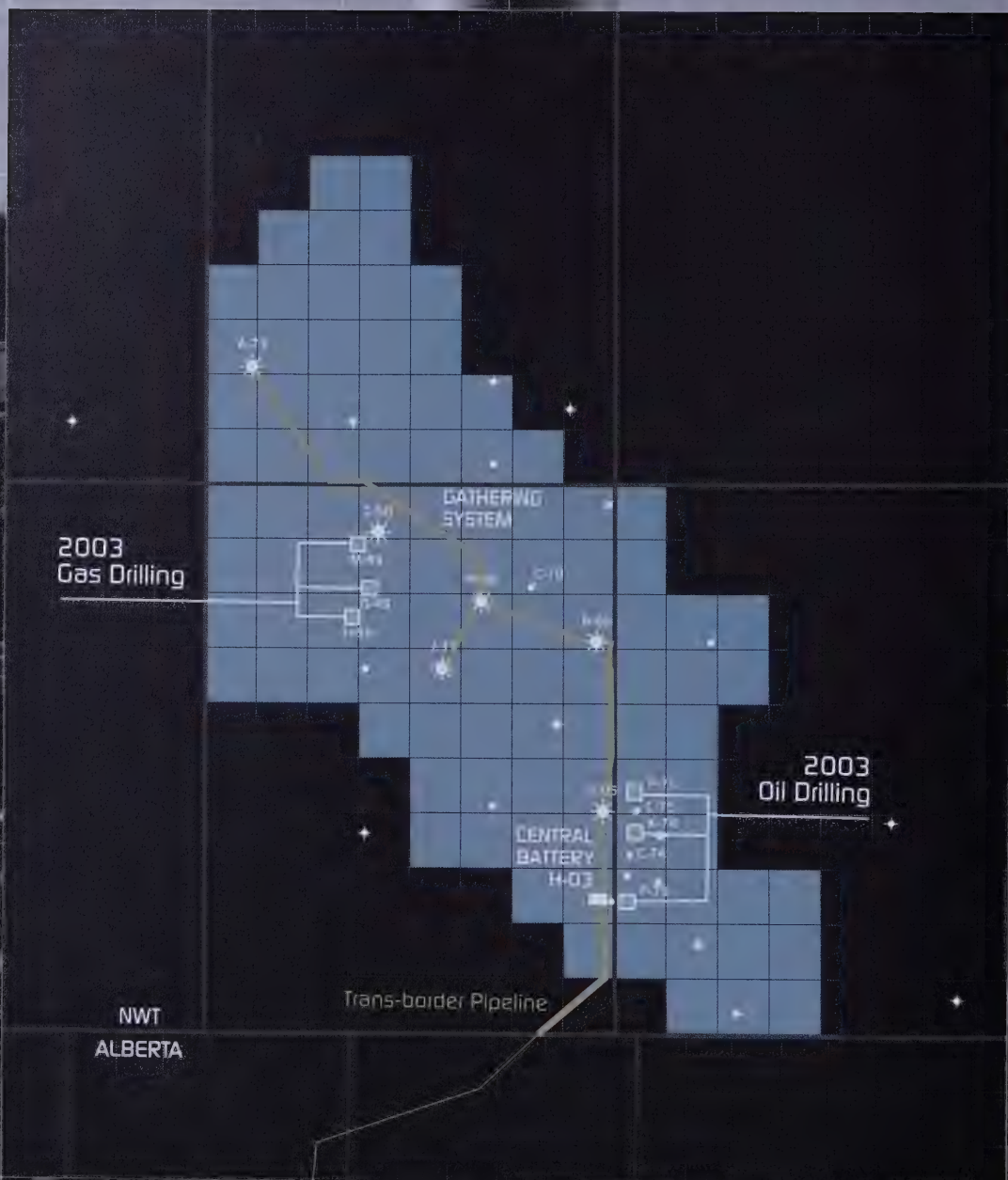
CATHERWICK
SYSTEM

2003
Oil Drilling

CENTRAL
BATTERY
H-03

NWT
ALBERTA

Trans-border Pipeline



Areas of Interest Cameron Hills, NWT

REFERENCE

Six natural gas wells were tied-in and placed on production in early 2002 (A-73, N-28, J-37, and C-50 Sulphur Point) (A-5 Slave Point) (B-08 Keg River) The tie-in project consisted of constructing: a gathering system, central residence located at H-03, 15 kilometer 12-inch transborder pipeline, 57 km 12-inch pipeline that connects the transborder pipeline to the Bistcho Plant, and installing 3,200 hp of booster compression at Bistcho. At year's end, four of the natural gas wells remained on production. Wells B-08 and J-37 experienced liquid loading problems and could not be restarted. The remaining four wells provided a year-end exit rate of 10.5 MMcf/d. A workover to open an additional and separate pay interval in the Sulphur Point is planned for the J-37 well in first quarter of 2003 in an attempt to return this well to producing status.

Activities through the balance of 2002 were focused on technical evaluation and obtaining regulatory approval for an oil project based on drilling success in the first quarter and the drilling of gas prospects identified with a 3D seismic program conducted in the first quarter.

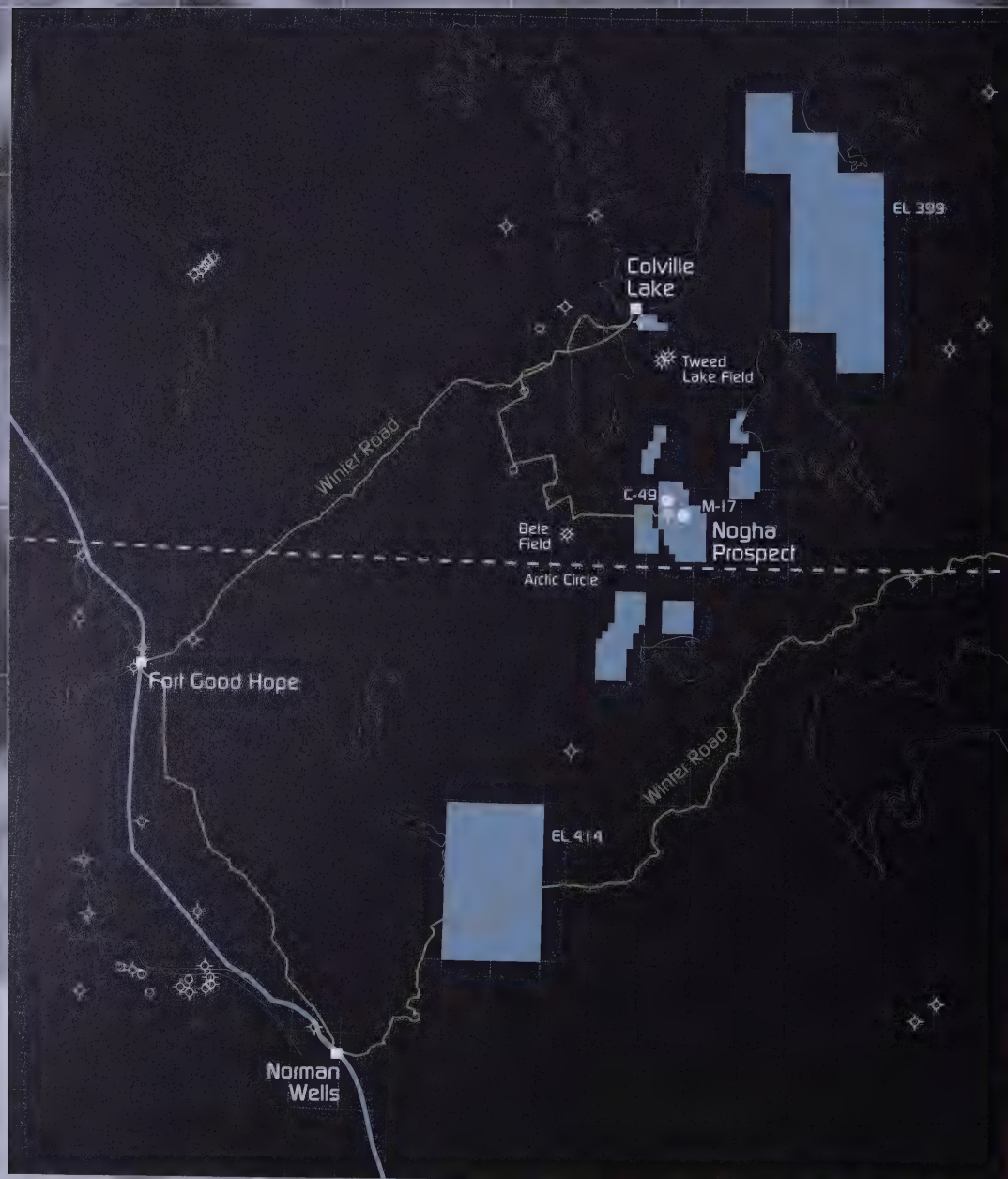
Planned 2003 activity includes an oil pilot project and additional natural gas well drilling. The following provides detail for both oil and natural gas activity:

Three new wells to further delineate Sulphur Point oil (F-73, K-74 and F-75) will be drilled, in addition to recompletion of an interpreted oil zone in two existing wells (C-75 and C-19). The combination of the new drilling activity and the existing oil wells should result in a total of five oil wells that can be tied-in and placed on production. The existing C-19 well is a significant distance outside the oil pilot area and will be production tested during the winter season. Substantial new infrastructure is required to accomplish year-round oil production from the Cameron Hills area. Included are field gathering for five wells, an oil battery, solution gas compression and a pumpjack for the H-03 oil well. Modifications are required at the Bistcho plant site and 55 kilometres of 4" pipeline will be built to move oil from Bistcho to Zama. An initial gross rate of 1,500 Bbl/d is expected from the oil pilot along with associated gas.

AIF
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Three natural gas well locations targeting primarily Sulphur Point gas are planned for the area covered by 3D seismic acquired in the first quarter of 2002. These locations (D-49, M-49 and H-58) are all in good proximity to existing infrastructure and are needed to offset decline in existing producers. The anticipated initial production gain is expected to be 5 MMcf/d of net sales gas to Paramount.

An additional 77 square kilometers of 3D seismic is planned to provide future expansion of the oil project and further the drilling of natural gas wells in subsequent drilling seasons.



Areas of Interest Colville Lake, NWT

Situated at the Arctic Circle, some 1,850 kilometers north of Calgary, the Colville Lake Area has significant potential for large-scale gas and condensate reserves trapped structurally and stratigraphically within sandstones of Cambrian Age. The area is vastly under explored with only 21 wells drilled to 2002 in an area of more than 200 Alberta Townships. Despite this sparse testing the area has yielded over 200 Bcf in three earlier discoveries. Paramount over the last three years has amassed a significant land base in the Colville area of some 650,000 acres, the size of approximately 28 Alberta townships. This land was acquired with the acquisition of a concession agreement with the local first nations people and through the purchase of two Federal Exploration Licenses ("EL 399 and EL 414").

In order to accelerate the pace of exploration of the newly acquired lands, in late 2002 Paramount acquired a 50 percent partner in the area. Apache Canada as part of the partnership agreement participated in the drilling of two 1,500 meter wells on Paramount's Nogha prospect. The first well Nogha C-49, operated by Apache, was drilled, cased and completed as a successful gas well. The second well Nogha M-17, operated by Paramount, was drilled down structure from the C-49 well and was cased and completed as a second successful gas well. Plans are now underway to evaluate the potential for completing additional zones within these newly drilled wells, to delineate further drilling locations on the Nogha prospect and to identify additional drilling opportunities on similar structures in the area.

In addition to the evaluation of the Nogha prospect block, the partners carried out a new 156 kilometer 2D seismic survey on EL 399. This license covers approximately 120,496 ha and was awarded to Paramount in July 2000 for a work commitment bid of \$8.4 million. The newly shot seismic, together with trade data previously purchased and reprocessed, will be used to define potential drilling locations on EL 399 for next winter.

In 2001 Paramount obtained EL 414 between Colville Lake and Norman Wells for a work commitment bid of \$10.7 million. This license has an area of approximately 84,880 ha and is currently being evaluated by the partners using previously purchased and reprocessed trade data. This data will be used to assist in the planning of a 2D seismic survey that will be carried out on EL 414 later in 2003.

A map of an oil and gas field area, likely in the Bakken region, showing various production zones. The map is dark with lighter, textured areas representing geological features. Numerous small squares and rectangles are scattered across the map, each connected by a thin line to a text box containing production data. The text boxes are arranged in several columns, with some grouped together. The data includes names of fields or zones, followed by production rates in MMcf/d and Bbl/d. A legend in the bottom left corner identifies two types of land: Paramount Lands (represented by a blue square) and Summit Lands (represented by a white square). The map shows a complex network of these fields, with some larger, more prominent areas and many smaller, more isolated ones. The production data is presented in a clear, organized manner, allowing for easy comparison between different fields and zones.

Clarke Lake

7.0 MMcf/d

Mirage

6.0 MMcf/d

383 Bbl/d

Sturgeon Lake

0.15 MMcf/d

254 Bbl/d

Chain/Craigmyle

3.9 MMcf/d

66 Bbl/d

Enchant/Rellaw

4.5 MMcf/d

396 Bbl/d

Sylvan Lake

1.9 MMcf/d

178 Bbl/d

Other

3.7 MMcf/d

382 Bbl/d

Fox Creek

17.1 MMcf/d

279 Bbl/d

Two Creek

3.7 MMcf/d

16 Bbl/d

Kakwa

0.75 MMcf/d

156 Bbl/d

Other

2.3 MMcf/d

312 Bbl/d

Talagwa

412 Bbl/d

Loughheed

257 Bbl/d

Parkman

86 Bbl/d

Benson

90 Bbl/d

Other

215 Bbl/d

Rabbit Hills

1 MMcf/d

272 Bbl/d

Other

189 Bbl/d

Knudson

420 Bbl/d

Beaver Creek

0.3 MMcf/d

185 Bbl/d

Other

265 Bbl/d

■ Paramount Lands

■ Summit Lands

Areas of Interest

Summit Resources Limited Acquisition

Paramount acquired all of the issued and outstanding shares of Summit Resources Limited ("Summit") for \$7.40/share and the assumption of \$81 million of net debt for a total cash consideration of \$338 million. Paramount was able to secure in advance, a "lock-up" agreement representing 55 percent of the outstanding shares, which provided some certainty to the deal.

Summit had reported first quarter production for 2002 of 13,531 BOE/d comprised of 52.3 MMcf/d of natural gas production and 4812 Bbl/d of oil and natural gas liquid production. Reserves of Summit had been evaluated at December 31, 2001 to be 115.6 Bcf of proven (150.3 Bcf proven plus probable) natural gas reserves and 10.5 MMBbls proven (14.2 MMBbls proven plus probable) crude oil and natural gas liquid reserves which represented a 6 year proven reserve life index (7.9 year proven plus probable). In addition, Summit held 375,000 acres of undeveloped land.

Summit's major producing areas were as follows;

District	Production		
	Gas MMcf/d	Oil/NGLs Bbl/d	BOE/d @ 6:1
West Central Alberta	30.0	1,400	6,400
Northeast B.C.	7.0	-	1,170
Southern Alberta	14.0	1,022	3,355
Southeast Saskatchewan		1,060	1,060
Subtotal Canada	51.0	3,482	11,985
Montana	1.0	460	626
North Dakota	0.3	870	920
Subtotal U.S.	1.3	1,330	1,546
Total Summit	52.3	4,812	13,531

The best fit of Summit assets comes in the West Central Alberta core area where 6,400 BOE/d (47.3 percent) fall coincident to or directly offsetting Paramount lands in what, after the Trust creation, is Paramount's largest producing core area. Paramount expects to see significant benefits in operating and capital cost savings as a result. The Clarke Lake asset in Northeastern British Columbia is also a good fit with Paramount's N.E. B.C./Liard NWT core area. The Southern Alberta, SE Saskatchewan, U.S.A. properties now comprise Paramount's new Southern Core Area and provide 5,961 BOE/d of production making it Paramount's second largest producing Core Area. Paramount was quite fortunate to have acquired Summit as it added production at a reasonable cost and growth opportunities to Paramount's portfolio.

Management's Discussion & Analysis ("MD&A")

Paramount is pleased to report its financial and operating results for the year ended December 31, 2002.

The following discussion of financial position and results of operations should be read in conjunction with the Consolidated Financial Statements and Notes thereto. It offers Management's analysis of Paramount's historical financial and operating results and provides estimates of Paramount's future financial and operating performance based on information currently available. Actual results will vary from estimates and the variances may be significant.

Paramount Resources Ltd. ("Paramount" or the "Company") is an exploration, development and production company with established operations in Alberta, British Columbia, Saskatchewan, the Northwest Territories, Montana, North Dakota and California. The Company has patiently executed its corporate growth strategy, focusing on natural gas as a commodity, and high impact exploration as the cornerstone to future success. Management's vision continues to be based on the long-term fundamentals for oil and natural gas in North America. During 2002, Paramount continued to focus its efforts on building a strong asset base through exploration and development, and the acquisition of Summit Resources Limited ("Summit").

SIGNIFICANT EVENTS

• Acquisition of Summit Resources Limited

On June 28, 2002, Paramount closed the acquisition of Summit Resources Limited for cash consideration of \$251.4 million and assumed net debt of \$81.0 million. The acquisition diversified the Company's production base and consolidated certain working interests in Central Alberta which the Company believes are highly prospective.

• Creation of an Independent Energy Trust

In conjunction with Paramount's acquisition of Summit, the Company announced its intention to create an independent Energy Trust (the "Trust"), providing shareholders an investment which would complement Paramount's traditional exploration and development strategy.

During the first quarter 2003, all necessary regulatory clearances with respect to the Canadian prospectus and a US Registration Statement were received. Paramount subsequently transferred a portion of its Northeast Alberta assets to the Trust and issued a \$51 million dividend in kind of Trust Units received from the Trust to its shareholders. On March 11, 2003, the Trust closed a rights offering, the proceeds of which partially capitalized the Trust and allowed it to purchase from Paramount additional assets in Northeast Alberta.

• Settlement of Bitumen/Natural Gas Co-Production Issue

On June 27, 2002, Paramount received compensation of \$47.1 million in settlement for the Surmont shut-in order of May 1, 2000.

• Sale of Remaining Investment in Peyto Exploration and Development Corp.

Paramount monetized its remaining investment in Peyto Exploration and Development Corp. to realize cash proceeds of \$45.0 million in 2002 for a net gain of \$40.1 million.

HIGHLIGHTS

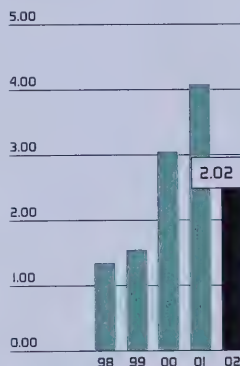
- Cash flow totaled \$259.9 million or \$4.37 per share.
- Natural gas sales averaged 241 MMcf/d; crude oil and natural gas liquids production averaged 5,663 Bbl/d.

Accounting Policy. Paramount follows the "successful efforts" method of accounting for its petroleum and natural gas operations. This method, unlike the alternative "full cost" accounting method, usually generates a more conservative value for net earnings as exploration expenditures, including exploratory dry hole costs, geological and geophysical costs, lease rentals on undeveloped properties as well as the cost of surrendered leases and abandoned wells are expensed rather than capitalized in the year incurred. However, to make reported cash flow results comparable to industry practice, Paramount reclassifies geological and geophysical costs as well as surrendered leases and abandonment costs from operating to investing activities.

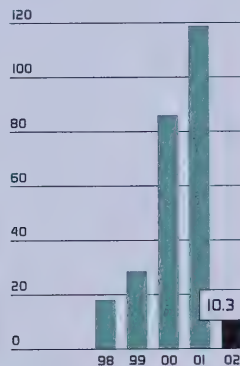
Management's Discussion & Analysis

RESULTS

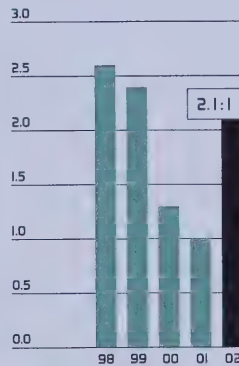
Cash Netback*
(\$/Mcfeq)



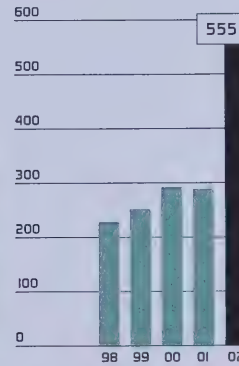
Net Earnings
(\$ millions)



Net Debt to Cash Flow Ratio
(ratio)



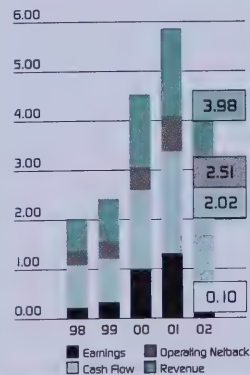
Net Debt
(\$ millions)



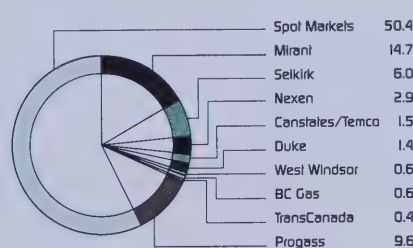
* excludes gain on sale of investments.

RESULTS

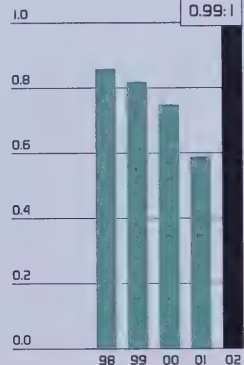
Revenue Reconciliation
(\$/Mcfeq)



Natural Gas Sales Distribution
(88.1 Bcf)



Operating Debt to Equity Ratio
(ratio)



Management's Discussion & Analysis

REVENUE

Production Revenue (thousands of dollars)

	2002	2001	2000
Natural gas	\$ 311,438	\$ 481,436	\$ 375,746
Crude oil and natural gas liquids	72,750	28,442	21,676
Commodity hedging gain (loss)	46,813	15,808	(5,952)
Gain on sale of short-term investments	40,830	2,982	—
Other	2,111	(295)	—
Gross revenue	\$ 473,942	\$ 528,373	\$ 391,470

Paramount's financial success is contingent upon the growth of reserves and production volumes and the economic environment that creates a demand for natural gas and crude oil. Such growth is a function of the amount of cash flow that can be generated and reinvested into a successful capital expenditure program. To protect cash flow against commodity price volatility, the Company will, from time to time, manage cash flow by utilizing commodity price hedges. The hedging program is generally for periods of less than one year and restricted to a maximum of 50 percent of Paramount's current production volumes.

Petroleum and natural gas revenue totaled \$431.0 million in 2002, as compared to \$525.7 million in 2001 (2000 – \$391.5 million). The decrease in revenue results from lower commodity prices received during the year. Weaker natural gas demand resulted in a decrease of 33 percent in Paramount's average natural gas sales price to \$4.08/Mcf as compared to \$6.12/Mcf in 2001 (2000 – \$4.59/Mcf). Included in petroleum and natural gas sales are \$46.8 million of commodity hedging gains attributed primarily to natural gas hedges. On a per unit basis the 2002 price includes approximately \$0.55/Mcf profit from natural gas commodity hedges that were in place during the year. Natural gas sales volumes averaged 241 MMcf/d in 2002 as compared to 225 MMcf/d in 2001 (2000 – 220 MMcf/d). The increase in natural gas sales volumes is attributed to the acquisition of Summit effective June 28, 2002, which added approximately 50 MMcf/d of natural gas production.

Oil and natural gas liquids prices averaged \$34.64/Bbl, as compared to \$35.48/Bbl in 2001 (2000 – \$37.80/Bbl). Oil and natural gas liquids production increased 162 percent to average 5,663 Bbl/d in 2002 as compared to 2,165 Bbl/d in 2001 (2000 – 1,571 Bbl/d). This increase is attributable to the acquisition of Summit which at the time of acquisition produced approximately 5,000 Bbl/d of oil and natural gas liquids.

Paramount's 2002 production profile continues to be significantly weighted to natural gas but the Company has increased its oil and natural gas liquids production with the Summit acquisition. In 2002 natural gas revenue contributed 83 percent of Paramount's total petroleum and natural gas revenue compared to 95 percent in 2001.

Fourth quarter petroleum and natural gas revenue totaled \$135.5 million as compared to \$87.7 million for the comparable quarter in 2001. The increase in sales resulted from an increase in production volumes associated with the acquisition of Summit, as well as an increase in natural gas prices, which averaged \$4.60/Mcf during the quarter as compared to \$4.17/Mcf for the comparable quarter in 2001. Natural gas sales averaged 263 MMcf/d for the fourth quarter of 2002 compared to 218 MMcf/d for the comparable quarter in 2001. Oil and natural gas liquids sales averaged 8,552 Bbl/d in the fourth quarter of 2002 as compared to 2,002 Bbl/d for the comparable quarter in 2001.

At December 31, 2002, Paramount had the following natural gas commodity price hedges in place representing approximately 40 percent of Paramount's average 2002 production:

Management's Discussion & Analysis

Volume		Term
AECO	Price	
10,000 GJ/d	\$ 5.46	November 2002 – October 2003
20,000 GJ/d	\$ 5.06	November 2002 – October 2003
20,000 GJ/d	\$ 5.25	November 2002 – October 2003
NYMEX		
20 MMcf/d	US \$ 3.83	November 2002 – October 2003
20 MMcf/d	US \$ 3.90	November 2002 – October 2003
10 MMcf/d	US \$ 4.10	November 2002 – October 2003
WTI		
1,000 Bbl/d	US \$ 24.07	May 2002 – April 2004
1,000 Bbl/d	US \$ 24.33	January 2003 – December 2003

The unrealized loss on these financial hedges at December 31, 2002 totaled \$28.7 million.

The Company also has in place foreign exchange hedges, which have fixed the exchange rate on US \$40.9 million for CDN \$58.6 million over the next three years at CDN \$1.4322. For the year ended December 31, 2002, gross revenue included losses from foreign currency hedging activity of \$3.4 million (2001 – \$1.7 million).

During 2002, approximately 43 percent of Paramount's natural gas sales were under long-term contracts to gas aggregators and direct-sales purchasers as compared to 42 percent and 46 percent for 2001 and 2000, respectively.

Natural Gas Sales per Market Group		2002		2001		2000	
Long-term Contracts		Bcf	%	Bcf	%	Bcf	%
Mirant	Midwestern US, Pacific Northwest US, California and Quebec	14.7	16.6	17.4	21.2	19.6	24.3
Progas	Northeastern US	9.6	10.9	8.1	9.9	7.2	8.9
Canstates / Temco	Northeastern US	1.5	1.7	1.9	2.2	3.2	4.0
TransCanada	Eastern Canada	0.4	0.5	2.7	3.3	1.2	1.5
Subtotal – aggregators		26.2	29.7	30.1	36.6	31.2	38.7
Direct Sales							
Nexen	Midwestern US	2.9	3.3	—	—	—	—
Selkirk	Northeastern US	6.0	6.8	4.5	5.5	6.0	7.4
West Windsor	Eastern Canada	0.6	0.7	—	—	—	—
BC Gas	British Columbia	0.6	0.7	—	—	—	—
Duke	AECO	1.4	1.6	—	—	—	—
Subtotal – direct sales		11.5	13.1	4.5	5.5	6.0	7.4
Subtotal – long-term contacts		37.7	42.8	34.6	42.1	37.2	46.1
Short-term markets							
Spot	Chicago	3.2	3.6	—	—	—	—
Spot	Eastern Canada	2.7	3.1	—	—	—	—
Spot	California	13.8	15.7	14.6	17.8	14.6	18.1
Spot	Alberta / Waddington	30.7	34.8	32.9	40.1	28.7	35.8
Total ⁽¹⁾		88.1	100.0	82.1	100.0	80.5	100.0

(1) Natural gas sales for 2000 reflect a 366-day year.

Management's Discussion & Analysis

For 2003, revenues will be impacted by drilling success and production volumes as well as external factors such as the market for natural gas, the exchange rate of the Canadian dollar relative to the US dollar and the West Texas Intermediate ("W.T.I.") price for crude oil. Additionally, the disposition of producing natural gas assets in Northeast Alberta to the Trust will reduce production volumes and corresponding reserves. Natural gas production in this area averaged approximately 97 MMcf/d during 2002, exiting the year at 90 MMcf/d. A minor asset disposition package is also currently being marketed, with bids expected to close early in 2003.

The Company anticipates a continued positive trend in commodity prices for 2003 relative to the prices received in 2002.

GAIN ON SALE OF SHORT-TERM INVESTMENTS

During the year Paramount disposed of 8.7 million shares of Peyto Exploration and Development Corp. at an average price of \$5.17 per share for net proceeds of \$45.0 million resulting in a gain of \$40.1 million. In 2002, Paramount also disposed of 1.25 million shares of Triquest Energy Corp. at an average price of \$2.98 per share for net proceeds of \$3.7 million resulting in a gain of \$0.7 million. Paramount routinely utilizes a portion of its working capital to make short-term investments in private and publicly traded oil and gas companies. Accordingly, related gains and losses are included in cash flow from operations.

BITUMEN/NATURAL GAS CO-PRODUCTION

On February 28, 2002, Paramount entered into a Memorandum of Agreement with the Province of Alberta and Conoco Canada Resources Ltd. ("Conoco"), effective May 1, 2000. The Memorandum of Agreement provided, inter alia, for compensation of \$85 million to be paid to the Surmont Gas Producers by the Alberta Crown in the form of reduced royalties as well as the granting to the Province of Alberta by the Surmont Gas Producers of an 11 percent gross overriding royalty encompassing certain wells, lands and leases affected by the shut-in order of May 1, 2000. Compensation of \$47.1 million was received in June 2002. This amount has been recorded in the Consolidated Statement of Earnings, net of the net book value of wells, lands and leases in the affected area of \$9.1 million.

ROYALTIES

Royalties are paid by Paramount to the owners of mineral rights with whom the Company holds leases. Paramount has mineral leases with the Crown (Provincial and Federal Governments), freeholders and other operators with whom the Company has joint interests.

Royalties (thousands of dollars)

	2002	2001	2000
Crown royalties	\$ 71,535	\$ 94,253	\$ 76,470
Other royalties	3,658	5,953	4,587
	75,193	100,206	81,057
Alberta Royalty Tax Credit	(749)	(500)	(516)
Total royalties	\$ 74,444	\$ 99,706	\$ 80,541
Average corporate royalty rate	17.2%	18.9%	20.6%

Alberta gas Crown royalties are a cash royalty calculated on the Crown's share of production using the Alberta Reference Price. The Alberta Reference Price is the monthly weighted average price for gas consumed in Alberta and gas exported from Alberta reduced for allowances for transportation and marketing. A subsequent cost-of-service credit is applied to account for the Crown's share of allowable capital and processing fees to arrive at the net royalty.

For 2002, royalties net of the Alberta Royalty Tax Credit ("ARTC") decreased to \$74.4 million from \$99.7 million in 2001 (2000 - \$80.5 million) due to lower natural gas commodity prices. As a percentage of production revenue, Paramount's corporate royalty rate decreased to 17.2 percent as compared to 18.9 percent in 2001 (2000 - 20.6 percent). Fourth-quarter royalties reflected the increase in production volumes and commodity prices compared to the prior year's quarter, and increased to \$28.2 million as compared to \$12.4 million during the fourth quarter 2001.

Management's Discussion & Analysis

For 2003, Paramount's average corporate royalty rate is expected to increase, giving effect to a corporate average natural gas price which will be less than the Alberta Reference Price on which royalties are calculated. This results from expected losses on the Company's hedging program which are netted from revenues in deriving at petroleum and natural gas sales. As in 2002, there will continue to be minimal royalties paid to the Federal Government for production from projects in the Northwest Territories. Royalties for these projects are subject to payout accounts.

OPERATING EXPENSES

Operating Expenses (thousands of dollars)	2002	2001	2000
Operating expenses	\$ 86,067	\$ 61,045	\$ 47,974
Net operating expenses per Mcfeq	\$ 0.79	\$ 0.68	\$ 0.56

Paramount's 2002 operating expenses increased 41 percent to \$86.1 million from \$61.0 million in 2001 (2000 – \$48.0 million). On a unit-of-production basis, average operating costs increased to \$0.79 /Mcfeq from \$0.68/Mcfeq in 2001 (2000 – \$0.56/Mcfeq). Fourth-quarter operating costs increased to \$23.5 million as compared to \$17.5 million a year earlier, primarily due to the increased well base in the current quarter associated with the Summit acquisition.

Paramount constructs and operates plant facilities and gathering systems as a corporate strategy in order to control the flow of gas to market. These facilities incur fixed costs, which are in addition to the costs incurred at the well level, thereby increasing total operating expenses and the relative magnitude of the per unit costs. As production declines in the Company's traditional shallow gas areas, per-unit operating costs have increased. In new core areas facilities are constructed in anticipation of maximizing throughput, which in many cases has not yet been achieved. As optimization occurs and production volumes increase, per-unit costs should decrease to levels historically experienced by the Company. Operating costs associated with the Northeast Alberta assets totaled \$32.3 million in 2002 or \$0.91/Mcf.

For 2003, the Company expects operating costs on a per-unit-basis to decline marginally in recognition of the disposal of higher cost assets in Northeast Alberta.

GENERAL AND ADMINISTRATIVE EXPENSES

General and Administrative Expenses (thousands of dollars)	2002	2001	2000
Gross general and administrative expenses	\$ 30,868	\$ 26,374	\$ 18,982
Operating recoveries	(15,238)	(15,766)	(11,369)
General and administrative expenses before SARP	15,630	10,608	7,613
Share Appreciation Rights Plan ("SARP")	582	1,738	2,047
Net general and administrative expenses	\$ 16,212	\$ 12,346	\$ 9,660
Net general and administrative expenses per Mcfeq	\$ 0.15	\$ 0.14	\$ 0.11

General and administrative expenses, net of operating recoveries and before costs associated with the Share Appreciation Rights Plan ("SARP"), increased to \$15.6 million in 2002 as compared to \$10.6 million in 2001 (2000 – \$7.6 million). The increase is a result of additional salaries incurred in respect of the Summit office and field personnel, as well as additional administrative expenditures incurred to set up and staff the Trust. During the year, the Company increased head office staff by more than 40 percent and field staff by 60 percent in order to manage the Company's increasing asset base and to adequately staff the Trust. Cost increases associated with additional staffing levels include salary, benefits and rent. Paramount does not capitalize any general and administrative expenses.

Certain costs associated with setting up the Trust including legal and professional fees and advisory fees have been deferred and will be included as a cost associated with the disposition of the Northeast Alberta assets.

Management's Discussion & Analysis

At the Annual General Meeting of the shareholders held June 14, 2001, a resolution was approved to introduce an employee stock option plan as a substitute for the SARP. Share appreciation rights previously held by employees have been grandfathered until their expiry and are capped at a price of \$14.50, that being the grant price of an equal number of stock options. Under the SARP, participants are entitled to receive a benefit of an amount equal to the positive difference between the exercise price and \$14.50, which difference is charged to general and administrative expenses. At December 31, 2002, 238,000 SARPs remained outstanding. Employees exercising options have the choice of receiving cash from the Company for the positive difference between the exercise price and market price of the Company shares or receiving Company shares. Cash consideration paid is charged to general and administrative costs as incurred. During 2002, 177,000 options were exercised for consideration of \$0.6 million as compared to \$1.7 million in 2001 (2000 – \$2.0 million).

General and administrative expenses are expected to decline in 2003 as the Trust's operations will be excluded from Paramount's activities.

INTEREST EXPENSE

Interest Expense (thousand of dollars)

	2002	2001	2000
Interest expense	\$ 23,943	\$ 19,291	\$ 22,313
Total Debt, December 31	\$ 539,270	\$ 316,600	\$ 315,000
Debt to cash flow	2.07	1.04	1.41

Interest expense, representing interest on bank debt, increased to \$23.9 million from \$19.3 million in 2001 (2000 – \$22.3 million). The increase reflects significantly higher average debt levels during 2002 necessary to fund the Summit acquisition and the higher interest rates charged on the facility.

To finance the acquisition of Summit, the Company negotiated a \$600 million credit facility with a syndicate of Canadian Chartered banks, including a \$466 million production facility, a \$109 million bridge facility and a \$25 million working capital facility.

The term of the credit facility was initially structured to coincide with the closing of the transfer by Paramount to the newly formed Trust of a portion of its Northeast Alberta assets. As the Trust Rights Offering did not close until March 11, 2003, Paramount requested a formal extension of the existing facility. Upon closing of the Trust transaction the proceeds received by Paramount from the sale of the assets to the Trust have been used to permanently reduce bank indebtedness. On March 11, 2003, the term of the facility was extended to April 30, 2003, the bridge facility was paid down in its entirety and the credit facility reduced to \$315.5 million.

The Company had a note payable in the amount of \$33 million to Paramount Oil and Gas Ltd. The note was paid in full on March 7, 2003.

DRY HOLE COSTS

Under the successful efforts method of accounting, costs of drilling exploratory wells are initially capitalized and, if subsequently determined to be unsuccessful, are charged to dry hole expense. All other exploration costs, including geological and geophysical costs and annual lease rentals, are charged to exploration expense as incurred. For 2002, dry hole costs amounted to \$120.1 million as compared to \$8.9 million in 2001 and \$7.0 million in 2000. The provision includes \$4.7 million of costs associated with wells drilled in the current year, \$7.5 million of expired mineral leases, \$41.9 million associated with exploratory wells drilled in Canada in previous years, which the Company has determined will not be capable of production in economic quantities, and \$66.0 million related to certain exploratory projects in the United States which the Company has determined to be unsuccessful.

Geological and geophysical expenses decreased during 2002 to \$9.3 million (2001 – \$10.6 million; 2000 – \$6.8 million).

Management's Discussion & Analysis

DEPLETION, DEPRECIATION AND AMORTIZATION

The current year provision for depletion and depreciation expense totaled \$169.4 million as compared to \$105.4 million in 2001 (2000 – \$50.6 million). On a unit-of-production basis, depletion and depreciation costs averaged \$1.56 /Mcfeq as compared to \$1.21/Mcfeq in 2001 (2000 – \$0.59/Mcfeq). A larger depletable base due to the 2002 capital expenditure program and acquisition of Summit combined with reduced proved reserves increased the depletion factor during the fourth quarter.

Under the successful efforts method of accounting, depletion and depreciation is provided based on estimated proved recoverable reserves of each producing property. Capital costs associated with undeveloped land of \$218 million and non-producing petroleum and natural gas properties of \$149 million totaling \$367 million are excluded from capital costs subject to depletion in 2002 (2001 – \$402 million).

For 2003, the provision for depletion and depreciation is expected to decrease reflecting the disposition of assets in Northeast Alberta to the Trust and the corresponding reduction in production volumes. Increases or decreases in the depletion rate on a unit-of-production basis will be influenced by the reserves added through the 2003 drilling program or by acquisition.

FUTURE SITE RESTORATION AND ABANDONMENT COSTS

On an annual basis the Company reviews the liability for future site restoration and abandonment costs. For 2002 the provision totaled \$3.4 million as compared to \$2.4 million in 2001 (2000 – \$1.7 million). Current estimates for site restoration of all the Company's properties total approximately \$58 million, excluding assets in Northeast Alberta which were sold to the Trust during the first quarter of 2003. At December 31, 2002, \$23.0 million is reflected as an accumulated provision in the financial statements. This amount includes an accumulated provision for future site restoration of \$10.6 million included as part of the acquisition of Summit Resources Limited.

WRITE-DOWN OF PETROLEUM AND NATURAL GAS PROPERTIES

The Company has recorded a provision of \$31.3 million in 2002 (2001, 2000 – nil) in respect of impairment in certain producing non-core oil and gas assets located in Alberta and Southeast Saskatchewan.

INCOME TAXES

In 2002, Paramount recorded Large Corporations and other tax expense of \$9.2 million as compared to \$2.7 million in 2001 (2000 – \$2.3 million). The Company did not pay current income tax in 2002.

The future income tax benefit recorded in 2002 totaled \$46.9 million as compared to a \$56.1 million provision in 2001 (2000 – \$72.0 million provision). The Company also recorded a \$104.9 million future tax liability in respect of the Summit acquisition, which represents the tax effect of the difference between the value attributed to the Summit capital assets and the value of the related tax pools.

Estimated Income Tax Pools (millions of dollars)	December 31, 2002
Undepreciated capital costs (UCC)	\$ 313.5
Canadian oil and gas property expenses (COGPE)	302.2
Canadian exploration expenses (CEE)	9.4
Canadian development expenses (CDE)	148.1
Foreign exploration and development expenses (FEDE)	22.4
Other	0.7
Total estimated income tax pools	\$ 796.3

Paramount has available approximately \$796 million of unutilized tax pools at December 31, 2002. These tax pools will be available for deduction in 2003 in accordance with Canadian income tax regulations at varying rates of amortization.

Management's Discussion & Analysis

The disposition of the Northeast Alberta assets to the Trust will result in a reduction to COGPE and UCC.

CASH FLOW AND EARNINGS

(thousands of dollars)

	2002	2001	2000
Cash flow from operations	\$ 259,916	\$ 303,937	\$ 223,446
Net earnings	\$ 10,307	\$ 118,902	\$ 86,062
Weighted average shareholders' equity	\$ 540,745	\$ 477,705	\$ 373,623
After-tax rate of return (%)	1.9	24.9	23.0

Paramount's cash flow from operations decreased 14 percent to \$259.9 million or \$4.37 per basic common share (\$4.36 per diluted common share) from \$303.9 million or \$5.11 per basic and diluted common share in 2001 (2000 – \$223.4 million or \$3.76 per basic and diluted common share). The decrease is due to lower natural gas prices in 2002, offset somewhat by higher gas and liquids production during the year, as a result of the Summit acquisition. Fourth-quarter cash flow totaled \$62.1 million, an increase of 30 percent from \$47.7 million during the same period in 2001 (2000 – \$97.2 million). The weighted average common shares outstanding totaled 59.5 million in 2002, unchanged from 59.5 million in 2001 and 2000.

Earnings decreased to \$10.3 million or \$0.17 per basic common share (\$0.16 per diluted common share) compared to \$118.9 million or \$2.00 per basic and diluted common share in 2001 (2000 – \$86.1 million or \$1.45 per basic and diluted common share). The lower earnings in 2002 are a result of decreased cash flows, as well as larger non-cash charges for depletion and depreciation, dry hole costs, and the write-down of petroleum and natural gas properties. The impact of these charges was partially offset by a significant future tax recovery.

Paramount's three-year average after-tax rate of return on a book basis, based upon the weighted average shareholders' equity invested, was 17 percent.

NETBACKS

(\$/Mcfeg)

	2002	2001	2000
Gross revenue	\$ 3.98	\$ 5.87	\$ 4.54
Royalties (net of ARTC)	0.68	1.11	0.93
Operating costs	0.79	0.68	0.56
Operating netback	2.51	4.08	3.05
General and administrative	0.15	0.14	0.11
Lease rentals	0.04	0.05	0.06
Interest on long-term debt	0.22	0.21	0.26
Current and Large Corporations tax	0.08	0.31	0.03
Cash netback	\$ 2.02	\$ 3.37	\$ 2.59

Management's Discussion & Analysis

CAPITAL EXPENDITURES

(thousands of dollars)

	2002	2001	2000
Land	\$ 6,410	\$ 39,166	\$ 24,016
Geological and geophysical	9,303	10,646	6,784
Drilling	124,076	127,736	108,811
Production equipment and facilities	77,407	94,775	92,690
Exploration and development expenditures	217,196	272,323	232,301
Summit Resources Limited acquisition	449,648	—	—
Dry hole and geological and geophysical costs expensed	(129,361)	(19,590)	(13,803)
Petroleum and natural gas property impairment	(42,183)	—	—
Property acquisitions	28,610	19,048	61,550
Property dispositions	(4,995)	(11,763)	(34,205)
Other	2,349	1,166	3,205
Net capital expenditures	521,264	261,184	249,048
Adoption of new accounting policy	—	—	14,900
Change in cost of petroleum and natural gas properties	\$ 521,264	\$ 261,184	\$ 263,948

During 2002, expenditures for exploration and development activities totaled \$217.2 million as compared to \$272.3 million in 2001 (2000 – \$232.3 million). A total of 135 gross (99.4 net) wells were drilled during the year, including 15 gross (6.3 net) wells in the fourth quarter, compared to 196 gross (158.7 net) wells in 2001 (2000 – 163 gross, 128.7 net).

Net capital expenditures, including property acquisitions net of dispositions and the acquisition of Summit, amounted to \$521.3 million in 2002 as compared to \$261.2 million in 2001 (2000 – \$249.0 million).

Dry hole and geological and geophysical costs expensed totaled \$129.4 million in 2002 as compared to \$19.6 million in 2001 (2000 – \$13.8 million). Included in this amount are \$41.9 million associated with exploratory wells drilled in Canada in previous years, and \$66.0 million related to exploratory projects in the United States, which the Company has determined to be unsuccessful. Seismic costs during 2002 totaled \$9.3 million, as compared to \$10.6 million in 2001 (2000 – \$6.8 million).

In conjunction with the cash compensation received from the Alberta Crown related to the Surmont natural gas/bitumen issue, the Company has made a provision of approximately \$9.1 million (net of \$1.8 million accumulated depletion and depreciation) in recognition of the impairment in asset value resulting from the shut-in. This amount represents the net book value of the assets carried in the financial statements.

Paramount has also recorded a \$31.3 million impairment charge in respect of producing non-core oil and gas assets located in Alberta and Southeast Saskatchewan.

For 2003, Paramount's capital expenditure budget will be funded by internally generated cash flow and minor property dispositions. Any deficiency will draw upon existing credit facilities.

Management's Discussion & Analysis

INVESTMENTS

Short-Term Investments

The Company has the following short-term investments:

	Opening 2002 Shares	Purchased (Sold)	Closing 2002 Shares	Investment	Gain on Sale
Investments					
Peyto Exploration and Development Corp.	8,709,072	(8,709,072)	—	\$ —	\$ 40,105,111
Triquest Energy Corp. ⁽³⁾	5,000,000	(5,000,000)	—	—	725,000
Fox Creek Petroleum Corp.	1,028,571	1,144,591	2,173,162	2,234,000	
Jurassic Oil and Gas Ltd.	—	850,000	850,000	1,020,000	
Spearhead Resources Inc. ⁽¹⁾				5,000,000	
Altius Energy Corp. ⁽²⁾				4,690,240	
				\$ 12,944,240	\$ 40,830,111

(1) Spearhead Resources Inc. \$5 million 8 percent secured convertible debenture due September 12, 2003.

(2) Altius Energy Corp. \$2.7 million US 14 percent secured convertible debenture due April 9, 2005.

(3) During the year Triquest shares were consolidated on a 4-for-1 basis. Actual Triquest shares sold in 2002 were 1,250,000.

At December 31, 2002, all short-term investments were either debentures, or warrants or shares in private companies, therefore a market value for these assets is not readily accessible. The Company believes that the market value of its short-term investments approximates their book value.

Investment in Drilling Company

Paramount owns a 50 percent equity interest in Wilson Drilling Ltd., a private company established to operate three drilling rigs in Western Canada. The Company accounts for its interest using proportionate consolidation whereby its pro-rata share of the financial results is combined on a line-by-line basis with similar items in the Company's financial statements.

Investment in Pipeline Company

Paramount owns a 50 percent equity interest, before payout (45 percent after payout) in Shiha Energy Transmission Ltd., a private company established to transport natural gas from operations in the Liard core area, Northwest Territories to facilities in British Columbia. The Company accounts for its interest using proportionate consolidation whereby its pro-rata share of the financial results is combined on a line-by-line basis with similar items in the Company's financial statements.

Investment in Engineering Company

Paramount owns a 50 percent equity interest in a private company whose principal business is to provide consulting and technical engineering services. The Company accounts for its interest using proportionate consolidation whereby its pro-rata share of the financial results is combined on a line-by-line basis with similar items in the Company's financial statements.

DEFERRED REVENUE

During 2002, Paramount recognized in revenue \$39.4 million (2001 – \$1.2 million; 2000 – \$1.2 million) of deferred revenue primarily related to the settlement of natural gas commodity hedging contracts that were previously put in place to shelter the Company from declining gas prices. Paramount's accounting policy recognizes these gains in the accounting years of related production. The deferred hedging gains of \$7.8 million at December 31, 2002 will be recognized in revenue in 2003.

Management's Discussion & Analysis

BANK DEBT, LIQUIDITY AND RISK MANAGEMENT

Paramount's debt and equity capital structure as at December 31, 2002, was as follows:

(thousands of dollars, except per share)	AT COST			AT MARKET ⁽¹⁾		
	Amount	%	\$/Share ⁽²⁾	Amount	%	\$/Share ⁽²⁾
Bank debt, net of working capital	555,243	54	9.34	555,243	32	9.34
Future income taxes	279,855	27	4.71	279,855	16	4.71
Common share equity	190,193	19	3.20	891,879	52	15.00
Total	1,025,291	100	17.25	1,726,977	100	29.05

(1) Close at December 31, 2002 – \$15.00 /share.

(2) At December 31, 2002 – 59,458,600 basic common shares outstanding.

To finance the acquisition of Summit, the Company negotiated a \$600 million credit facility with a syndicate of Canadian Chartered Banks, including a \$466 million production facility, a \$25 million working capital facility, and a \$109 million bridge facility. Upon receipt of the Summit proceeds the bridge facility was permanently reduced by approximately \$47.1 million.

Upon closing of the Initial offering of units by Paramount Energy Trust (the "Trust"), the proceeds received by the Company in exchange for petroleum and natural gas properties sold to the Trust were used to permanently reduce bank indebtedness. Effective March 12, 2003, the available borrowing base under the current credit facility was reduced to \$315.5 million.

Also of significant importance to the Company is the Canada/US exchange ratio, since a substantial percentage of the natural gas sales and crude oil sales of the Company are made into and priced effectively on US markets. Any improvement in the Canadian dollar relative to its US counterpart will have a negative impact on the wellhead price received for our production. To manage this risk, Paramount has entered into currency swap agreements that have fixed the exchange rates on US \$40.9 million of future production revenue over the next three years at CDN \$58.6 million. In addition, the Company's US \$20 million bank loan is also designated as a currency hedge.

As at December 31, 2002, the Company's issued share capital consisted of 59,458,600 common shares (December 31, 2001 and 2000 – 59,453,600 common shares). Paramount instituted a "Normal Course Issuer Bid" to acquire a maximum of 5 percent of its issued and outstanding shares commencing September 1, 2001, and ending August 31, 2002. During 2002, no shares were purchased pursuant to the plan.

RISKS AND UNCERTAINTIES

Companies involved in the exploration for and production of oil and natural gas face a number of risks and uncertainties inherent in the industry. The Company's performance is influenced by commodity pricing, transportation and marketing constraints and government regulation and taxation.

Natural gas prices are influenced by the North American supply and demand balance as well as transportation capacity constraints. Seasonal changes in demand, which are largely influenced by weather patterns, also affect the price of natural gas.

Stability in natural gas pricing is available through the use of short and long-term contract arrangements. Paramount utilizes a combination of these types of contracts, as well as spot markets, in its natural gas pricing strategy. As the majority of the Company's natural gas sales are priced to US markets, the Canada/US exchange rate can strongly affect revenue.

Oil prices are influenced by global supply and demand conditions as well as for worldwide political events. As the price of oil in Canada is based on a US benchmark price, variations in the Canada/US exchange rate further affect Paramount's oil price.

Management's Discussion & Analysis

The Company's access to oil and natural gas sales markets is restricted, at times, by pipeline capacity. In addition, it is also affected by the proximity of pipelines and availability of processing equipment. Paramount controls as much of its marketing and transportation activities as possible in order to minimize any negative impact from these external factors.

The oil and gas industry is subject to extensive controls, regulatory policies and income taxes imposed by the various levels of government. These controls and policies, as well as income tax laws and regulations, are amended from time to time. The Company has no control over government intervention or taxation levels in the oil and gas industry; however, it operates in a manner to ensure that it is in compliance with all regulations and is able to respond to changes as they occur.

Paramount's operations are subject to the risks normally associated with the oil and gas industry including hazards such as unusual or unexpected geological formations, high reservoir pressures and other conditions involved in drilling and operating wells. The Company minimizes these risks using prudent safety programs and risk management, including insurance coverage against potential losses.

The Company recognizes that the industry is faced with an increasing awareness with respect to the environmental impact of oil and gas operations. Paramount has reviewed the environmental risks to which it is exposed and has determined that there is no current material impact on the Company's operations; however, the cost of complying with environmental regulations is increasing. Paramount will ensure continued compliance with environmental legislation.

KYOTO PROTOCOL ON GREENHOUSE GAS EMISSIONS

Canada is signatory to an International Treaty to achieve a 6 percent reduction from 1990 greenhouse gas emission levels by 2008-2012, which represents approximately a 25 percent cut from current levels. At this time the Company does not know what final course of action the Canadian or United States governments will take in this regard and accordingly cannot measure the potential risk to our business.

2003 CASH FLOW FORECAST AND SENSITIVITY ANALYSIS

The Company's earnings and cash flow are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond the control of the Company. Current volatility in commodity prices creates uncertainty as to Paramount's cash flow and capital expenditure budget. The Company will therefore assess results throughout the year and revise budgets as necessary to reflect most current information. The following analysis assesses the magnitude of these sensitivities on the Company's 2003 cash flow using the following base assumptions:

a) 2003 Production

Natural gas	160 MMcf/d
Crude oil/liquids	7,000 Bbl/d

b) 2003 Average Prices

Natural gas	\$ 5.80/Mcf
Crude oil/liquids (W.T.I.)	US \$ 28.00/Bbl

c) 2003 Cash Flow

	\$ 200 million
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d) 2003 Net Capital Expenditures

	\$ 150 million
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Management's Discussion & Analysis

The following analysis assesses the estimated after-tax impact on cash flow with variations in production, price, interest and exchange rates:

Sensitivity (millions of dollars)	Cash Flow
Gas sales change of 10 MMcf/d	13.5
Gas price change of \$0.10/Mcf	3.7
Oil and natural gas liquids sales change of 100 Bbl/d	0.8
Oil and natural gas liquids price change of \$1.00/Bbl (W.T.I.)	1.6
Sensitivity to Canada/US exchange rate fluctuation of \$0.01 CDN	0.5
Average interest rate change of 1%	2.0

RECENT ACCOUNTING PRONOUNCEMENTS

Hedging Relationships

The CICA issued Accounting Guideline 13 – Hedging Relationships, which deals with the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The guideline establishes conditions for applying hedge accounting, but does not specify hedge accounting methods. The guideline is effective for fiscal years beginning on or after July 1, 2003. The Company anticipates that adoption of Accounting Guideline 13 will not have a material effect on its consolidated financial statements.

Impairment of Long-Lived Assets

The CICA recently issued Handbook Section 3063 – Impairment of Long-Lived Assets. This new Section establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets by profit-oriented enterprises. The section is effective for fiscal years beginning on or after April 1, 2003.

Under the new Section, impairment of long-lived assets held for use is determined by a two-step process, with the first step determining when an impairment is recognized and the second step measuring the amount of the impairment. To test for and measure impairment, long-lived assets are grouped at the lowest level for which identifiable cash flows are largely independent. An impairment loss is recognized when the carrying amount of a long-lived asset exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. An impairment loss is measured as the amount by which the long-lived asset's carrying amount exceeds its fair value. This represents a significant change to Canadian GAAP, which previously measured the amount of the impairment as the difference between the long-lived assets carrying value and its net recoverable amount (i.e. undiscounted cash flows plus residual value). The potential impact of this pronouncement on the Company's consolidated financial statements is not known at present.

Disposal of Long-Lived Assets and Discontinued Operations

The CICA recently issued Handbook Section 3475 – Disposal of Long-Lived Assets and Discontinued Operations, which establishes standards for the recognition, measurement, presentation and disclosure of the disposal of long-lived assets by profit-oriented enterprises. It also establishes standards for the presentation and disclosure of discontinued operations.

Although earlier adoption is encouraged, section 3475 applies to disposal activities initiated by a company's commitment to a plan on or after May 1, 2003. The Company anticipates that adoption of this pronouncement will not have a material effect on its consolidated financial statements.

Financial Statements

MANAGEMENT'S REPORT TO SHAREHOLDERS

The accompanying consolidated financial statements of Paramount Resources Ltd. and all the information in this Annual Report are the responsibility of management and have been approved by the Board of Directors.

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly, in all material respects. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the consolidated financial statements.

Management maintains systems of internal accounting and administrative controls of high quality, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are appropriately accounted for and adequately safeguarded.

The Audit Committee of the Board of Directors consists of non-management directors. The Committee meets quarterly with management as well as with the external auditors to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues to satisfy itself that each party is properly discharging its responsibility, and to review the Annual Report. The Committee reports its findings to the Board for consideration when approving the consolidated financial statements for issuance to the shareholders. The Committee also considers, for review by the Board and approval by the shareholders, the engagement or re-appointment of the external auditors.

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditor, in accordance with auditing standards generally accepted in Canada on behalf of the shareholders. Ernst & Young LLP has full and free access to the Audit Committee and Management.



James H. T. Riddell
President



David J. Broshko, C.A.
Chief Financial Officer

March 18, 2003

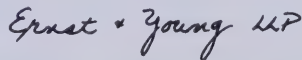
AUDITORS' REPORT

To the Shareholders of Paramount Resources Ltd.:

We have audited the consolidated balance sheets of Paramount Resources Ltd. as at December 31, 2002 and 2001, and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.



Chartered Accountants

March 14, 2003
Calgary, Canada

Consolidated Balance Sheets

As at December 31 (thousands of dollars)

2002

2001

ASSETS (note 6)

Current Assets

Cash	\$ -	\$ 740
Short-term investments		
(market value: 2002 - \$14,168; 2001 - \$29,598) (note 14)	14,168	13,932
Accounts receivable (note 11)	91,042	72,356
Prepaid expenses	19,213	13,320
Deferred hedging loss (note 11)	-	17,638
	124,423	117,986

Property, Plant and Equipment (note 4)

Petroleum and natural gas properties, at cost	1,961,369	1,440,105
Accumulated depletion and depreciation	(549,408)	(381,768)
	1,411,961	1,058,337
	\$ 1,536,384	\$ 1,176,323

LIABILITIES AND SHAREHOLDERS' EQUITY

Current Liabilities

Accounts payable and accrued liabilities	\$ 140,396	\$ 92,084
Shareholder loan (notes 7 and 15)	33,000	-
Bank loans (notes 6 and 15)	498,097	-
	671,493	92,084

Bank loans (notes 6 and 15)

- 314,148

Drilling rig indebtedness (note 5)

1,443 2,452

Mortgage (note 6)

6,730 -

Provision for future site restoration and abandonment costs

22,954 8,955

Deferred revenue (note 11)

7,804 1,427

Future income taxes (note 9)

279,855 221,873

318,786 548,855

Commitments and Contingencies (notes 5, 11 and 13)

Shareholders' Equity

Share capital (note 8)

Issued and outstanding

59,458,600 common shares (2001 - 59,453,600 common shares) 190,193 189,320

Retained earnings

355,912 346,064

546,105 535,384

\$ 1,536,384 \$ 1,176,323

See accompanying notes to consolidated financial statements.

On behalf of the Board



C.H. Riddell
Director



J. B. Roy
Director

Consolidated Statements of Earnings and Retained Earnings

Years ended December 31 (thousands of dollars except for per share amounts)	2002	2001
Revenue		
Petroleum and natural gas sales	\$ 431,001	\$ 525,686
Royalties (net of ARTC)	(74,444)	(99,706)
Gain on sale of investments (note 14)	40,830	2,982
Other income	2,111	(295)
	399,498	428,667
Expenses		
Operating	86,067	61,045
Surmont compensation – net (note 10)	(37,291)	–
Interest	23,943	19,291
General and administrative	16,212	12,346
Geological and geophysical	9,303	10,646
Dry hole costs (note 4)	120,058	8,944
Lease rentals	4,552	4,319
(Gain) loss on sales of property and equipment	(12)	1,537
Provision for future site restoration and abandonment costs	3,437	2,400
Depletion and depreciation	169,433	105,433
Write-down of petroleum and natural gas properties (note 4)	31,254	–
	426,956	225,961
Earnings (loss) before taxes	(27,458)	202,706
Income and other taxes (note 9)		
Current income tax	–	25,000
Large Corporations Tax and other	9,150	2,729
Future income tax (recovery)	(46,915)	56,075
	(37,765)	83,804
Net earnings	10,307	118,902
Retained earnings, beginning of year	346,064	228,934
Adoption of new accounting policies (note 3)	(459)	(1,772)
Retained earnings, end of year	\$ 355,912	\$ 346,064
Net earnings per common share		
– basic	\$ 0.17	\$ 2.00
– diluted	\$ 0.16	\$ 2.00
Weighted average common shares outstanding (thousands)		
– basic	59,458	59,454
– diluted	59,567	59,527

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

Years ended December 31 (thousands of dollars except for per share amounts)	2002	2001
Operating activities		
Net earnings	\$ 10,307	\$ 118,902
Add (deduct) non-cash items		
Write-down of Surmont assets	9,136	—
Depletion and depreciation	169,433	105,433
Write-down of petroleum and natural gas properties	31,254	—
(Gain) loss on sales of property and equipment	(12)	1,537
Provision for future site restoration and abandonment costs	3,437	2,400
Future income taxes	(46,915)	56,075
Non-cash general and administrative expenses	342	—
Add items not related to operating activities		
Surmont compensation	(46,427)	—
Dry hole costs	120,058	8,944
Geological and geophysical costs	9,303	10,646
Cash flow from operations	259,916	303,937
Increase (decrease) in deferred revenue	6,073	(1,160)
Change in non-cash operating working capital (note 12)	40,145	(17,677)
	306,134	285,100
Financing activities		
Bank loans – draws	146,952	3,627
Bank loans – repayments	(37,516)	—
Shareholder loan	33,000	—
Capital stock	72	—
Mortgage	6,730	—
Drilling rig indebtedness	(1,009)	(2,027)
	148,229	1,600
Cash flow provided by operating and financing activities	454,363	286,700
Investing activities		
Property, plant and equipment expenditures	209,848	266,172
Acquisition of Summit Resources Ltd. (note 2)	251,422	—
Petroleum and natural gas property acquisitions	28,420	8,345
Geological and geophysical costs	9,303	10,646
Proceeds on sale of property, plant and equipment	(4,423)	(2,857)
Surmont compensation	(46,427)	—
Change in non-cash investing working capital (note 12)	6,960	4,070
Cash flow used in investing activities	455,103	286,376
(Decrease) increase in cash	(740)	324
Cash, beginning of year	740	416
Cash, end of year	\$ —	\$ 740
Cash flow from operations per common share		
– basic	\$ 4.37	\$ 5.11
– diluted	\$ 4.36	\$ 5.11
Weighted average common shares outstanding (thousands)		
– basic	59,458	59,454
– diluted	59,567	59,527

See accompanying notes to consolidated financial statements.

Notes to the Consolidated Financial Statements

(all tabular amounts expressed in thousands of dollars)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Paramount Resources Ltd. (the "Company") is involved in the exploration and development of petroleum and natural gas primarily in Western Canada. The consolidated financial statements are stated in Canadian dollars and have been prepared by management in accordance with Canadian generally accepted accounting principles.

As a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. In management's opinion, the financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's accounting policies summarized below.

(a) principles of consolidation

The consolidated financial statements include the accounts of Paramount Resources Ltd. and its wholly owned subsidiaries Paramount Energy Trust, Paramount Resources US LLC, 586319 Alberta Ltd., Summit Resources Limited, Summit Resources Inc., 977554 Alberta Ltd. and 910083 Alberta Ltd.

The Company accounts for its interest in a drilling company, a drilling partnership, a pipeline company, and an engineering company where it exercises joint control using proportionate consolidation whereby its pro rata shares of all assets, liabilities, revenues and expenses are combined on a line-by-line basis with similar items in the Company's financial statements.

(b) joint operations

Certain of the Company's exploration, development and production activities related to petroleum and natural gas are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

(c) short-term investments

Short-term investments consist of common shares and convertible instruments held for sale. These investments are carried at the lower of cost and market value.

(d) inventory

Natural gas in storage is carried at the lower of cost and net realizable value. Cost includes all amounts incurred to produce or purchase the related gas, transportation to the storage facility and the cost of storage. At December 31, 2002 and 2001, there was no natural gas inventory.

(e) petroleum and natural gas properties

The Company follows the "Successful Efforts" method of accounting for petroleum and natural gas operations. Under this method the Company capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves. Exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry hole costs, are charged to earnings as incurred. Leasehold acquisition costs, including costs of drilling and equipping successful wells, are capitalized. The net costs of unproductive exploratory wells, abandoned wells and surrendered leases are charged to earnings in the year of abandonment or surrender. Gains or losses are recognized on the disposition of property, plant and equipment.

Depletion and depreciation of petroleum and natural gas properties including well development expenditures, production equipment, gas plants and gathering systems are provided on the unit-of-production method based on estimated proven recoverable reserves of each producing property or project. Depreciation of other equipment is provided on a declining balance method at rates varying from 4 to 30 percent.

Producing areas and significant unproved properties are assessed annually, or as economic events dictate for potential impairment. Any impairment loss is the difference between the carrying value of the asset and its undiscounted net recoverable amount.

Notes to the Consolidated Financial Statements

(all tabular amounts expressed in thousands of dollars)

(f) future site restoration and abandonment costs

Estimated future site restoration and abandonment costs are provided for in the financial statements. This estimate, net of expected recoveries, includes the cost of equipment removal and environmental cleanup based upon current regulations and economic circumstances at year end. Actual site restoration costs are deducted from the provision in the year incurred.

(g) foreign currency translation

The Company's foreign operations are considered integrated and are translated into Canadian dollars using the temporal method.

Monetary assets and liabilities denominated in US dollars are translated into Canadian dollars at exchange rates in effect at the balance sheet date. Other assets and liabilities are translated at the rates prevailing at the respective transaction dates. Revenues and expenses are translated at the average rate prevailing during the year. Translation gains and losses are reflected in income when incurred.

(h) financial instruments

The Company utilizes derivative financial instrument contracts to manage its exposure to petroleum and natural gas prices, the Canadian/US dollar exchange rate and interest rate fluctuations. Gains or losses from foreign exchange and commodity hedge contracts are recognized as part of petroleum and natural gas sales in the same period as the related production revenue. Amounts received or paid under interest rate swaps are recognized in interest expense as incurred. The fair values of these contracts are not reflected in the financial statements. The Company does not enter into derivative instruments for trading or speculative purposes.

The Company's policy is to designate formally each derivative financial instrument as a hedge of a specifically identified future revenue stream. The Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term to maturity, the notional amount and the commodity price basis in the instruments all match the terms of the future revenue stream being hedged.

Realized and unrealized gains or losses associated with derivative financial instrument contracts that have been terminated or cease to be effective prior to maturity are deferred as other current, or non-current, assets or liabilities on the balance sheet, as appropriate and recognized in earnings in the period in which the underlying hedged transaction is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any realized or unrealized gain or loss on such derivative instrument is recognized in earnings.

(i) measurement uncertainty

The amounts recorded for depletion and depreciation and impairment of petroleum property and equipment and for site restoration and abandonment are based on estimates of reserves, future costs, petroleum and natural gas prices and other relevant assumptions. By their nature, these estimates and those related to the future cash flow used to assess impairment are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

(j) income taxes

The Company follows the liability method of tax accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between financial reporting and income tax bases of assets and liabilities, and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in net income in the period in which the change occurs.

(k) stock option plan

The Company has a stock-based compensation plan consisting of a stock option plan and a stock appreciation rights plan. These plans are described in note 8.

Notes to the Consolidated Financial Statements

As options granted under the Company's employee stock option plan are issued at current market value, the option has no intrinsic value and therefore no compensation expense is recorded when the options are granted. Consideration paid by employees on the exercise of stock options is credited to share capital.

Awards issued under the stock appreciation plan that call for settlement in cash or other assets are measured as the amount by which the quoted market value of the shares of the Company's stock covered by the grant exceeds the market price of the underlying stock. Changes, either increases or decreases, in the quoted market value of those shares between the date of grant and the measurement date are charged to earnings in the period of change.

2. ACQUISITION OF SUMMIT RESOURCES LIMITED

On May 12, 2002, Paramount and Summit Resources Limited ("Summit") jointly announced that they had entered into an agreement pursuant to which Paramount would make an offer to purchase all of the issued and outstanding common shares of Summit for cash consideration of \$7.40 per share or approximately \$251.4 million, including acquisition costs. This transaction has been accounted for using the purchase method and is being accounted for as of the closing date of June 28, 2002.

The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. The Company has not yet completed its final evaluation of the assets acquired and the liabilities assumed. Therefore, the purchase price is subject to change.

Assets

Accounts receivable	\$ 13,997
Petroleum and natural gas properties	449,648
	463,645

Liabilities

Accounts payable	21,947
Future income taxes	104,897
Debt	74,513
Site restoration	10,562
Other liabilities	304
	212,223

Net assets acquired	\$ 251,422
----------------------------	-------------------

3. CHANGE IN ACCOUNTING POLICY

(a) stock-based compensation

Effective January 1, 2002, the Company adopted the new Canadian Institute of Chartered Accountants Standard on Stock-Based Compensation. Under this new standard, the Company's stock options and SARs, which can be settled in cash at the discretion of the employee, are accounted for at an amount equal to the difference between the exercise price and the fair value at the date of grant, resulting in a liability and corresponding compensation expense being recognized. The awards are remeasured at each reporting date. As permitted by the new standard, the Company applied the change retroactively for the SARs without restatement of individual prior periods. The impact of the adoption of the new standard on the financial statements as at January 1, 2002, was as follows:

Increase in liability	\$ 459
Decrease in retained earnings	\$ 459

The recognized expense for the year ended December 31, 2002, was \$342,000.

Notes to the Consolidated Financial Statements

This new standard requires the presentation of pro forma net earnings as if the Company had accounted for its employee stock options granted after December 31, 2001, under the fair value method. Had compensation cost for the Company's stock-based compensation plans been determined based on the fair value at the grant date of these awards, the Company's net earnings and earnings per share would have been reduced to the pro forma amounts indicated below:

Year ended December 31, 2002		
Net earnings	as reported	\$ 10,307
	pro forma	\$ 10,258
Net earnings per common share – basic	as reported	\$ 0.17
	pro forma	\$ 0.17
Net earnings per common share – diluted	as reported	\$ 0.16
	pro forma	\$ 0.16

The fair value for these options was estimated at the date of granting using a Black-Scholes Option Pricing Model with the following assumptions: weighted-average risk-free interest rate of 5.8 percent; dividend yield of 0 percent; weighted-average volatility factor of the expected market price of the Company's common shares of 39.5 percent; and a weighted-average expected life of the options of 4 years.

(b) treatment of foreign exchange gains and losses on long-term debt

In accordance with a newly issued Canadian Institute of Chartered Accountants ("CICA") accounting standard, the Company no longer defers and amortizes the gains or losses on foreign currency denominated long-term debt. Such gains or losses are reflected in the consolidated statement of earnings in the period incurred. The new standard has been applied retroactively without restatement of prior periods. The impact of the new standard on the results of the year ended December 31, 2002, was to increase net income by \$0.4 million and reduce current assets and retained earnings by \$1.8 million, representing the cumulative deferred foreign exchange losses at the beginning of the period.

(c) bank loans

On January 1, 2002, the Company adopted the new CICA recommendation regarding Balance Sheet Classification of Callable Debt Obligations and Debt Obligations Expected to be Refinanced. All borrowings where the lender has the right to demand repayment within 12 months (other than in the event of a default or breach of covenants) or where the lender has the right to refuse to roll over the borrowing for a further lending period of longer than 12 months are required to be classified as current liabilities.

The impact of this change has been to increase current liabilities by the amount of any such borrowings then in place. At December 31, 2002, this change has increased current liabilities by \$498.1 million and reduced long-term bank loans by a corresponding amount.

4. PROPERTY, PLANT AND EQUIPMENT

	2002		2001	
	Cost	Accumulated depletion and depreciation	Cost	Accumulated depletion and depreciation
Petroleum and natural gas properties	\$ 1,263,544	\$ 326,074	\$ 919,667	\$ 188,826
Gas plants, gathering systems and production equipment	670,769	214,655	507,976	185,527
Other	27,056	8,679	12,462	7,415
	\$ 1,961,369	\$ 549,408	\$ 1,440,105	\$ 381,768
Net book value	\$ 1,411,961		\$ 1,058,337	

Notes to the Consolidated Financial Statements

Capital costs associated with non-producing petroleum and natural gas properties totaling approximately \$367 million (2001 - \$402 million) are currently not subject to depletion.

The Company follows the Successful Efforts method of accounting for petroleum and natural gas operations. Under this method, the Company capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves. The cost of unproductive wells, abandoned wells and surrendered leases are charged to earnings in the year of abandonment or surrender. For the year ended December 31, 2002, the Company expensed \$120.1 million in dry hole costs (2001- \$8.9 million), of which \$66.0 million related to exploratory projects in the United States. A portion of the dry hole costs expensed related to prior year capital projects that were determined in the current year to have no future economic value. An additional provision of \$31.3 million has been recorded in respect of properties in Alberta and Saskatchewan whose net book values were in excess of undiscounted reserve values at December 31, 2002.

5. JOINT VENTURES

The consolidated financial statements include the Company's proportionate share of the assets and liabilities of its joint ventures as follows:

	2002	2001
Assets		
Current assets	\$ 1,278	\$ 1,983
Property, plant and equipment	8,520	6,822
	\$ 9,798	\$ 8,805
Liabilities and equity		
Current liabilities	\$ 9,239	\$ 6,908
Other liabilities	2,008	3,541
Deficit	(1,449)	(1,644)
	\$ 9,798	\$ 8,805
Revenues	\$ 2,591	\$ 1,842
Net earnings (loss)	\$ 195	\$ (1,542)
Cash flow provided by (used in)		
Operating activities	\$ 3,452	\$ 2,654
Financing activities	\$ 1,063	\$ (1,027)
Investing activities	\$ (4,515)	\$ (1,627)

Wilson Drilling Ltd. had a reducing term loan facility available to a maximum of \$6.0 million at December 31, 2002. The loan is repayable in equal quarterly installments of \$500,000 to December 2005. As at December 31, 2002, this facility had an effective interest rate of 5.5 percent (December 31, 2001 - 5.25 percent). Wilson Drilling Ltd. also has a long-term capital lease on one of its drilling rigs with a Canadian Chartered Bank in the amount of approximately \$3 million. The lease runs until August 2007 and has an imputed interest rate of 8.9 percent. The Company has provided a guarantee as collateral for these facilities. Earnings attributed to services provided to the Company have been eliminated from the accompanying consolidated statement of earnings.

6. BANK LOANS

To finance the acquisition of Summit, the Company negotiated a \$600 million credit facility with a syndicate of Canadian Chartered Banks, including a \$466 million production facility, a \$109 million bridge facility and a \$25 million working capital facility. The term of the facility is to April 30, 2003. Available borrowings under the bridge facility were permanently reduced by \$47.1 million upon receipt of the Surmont settlement.

Notes to the Consolidated Financial Statements

The term of the credit facility was initially structured to coincide with the closing of the transfer by Paramount of a portion of its Northeast Alberta assets to a newly formed Energy Trust. However, as this transaction had not yet closed as of December 31, 2002, Paramount has requested a formal extension of the existing facility. Accordingly, the loan facility has been classified as short-term. Upon closing of the "Trust" transaction proceeds received by Paramount from the sale of the assets to the Trust will be used to permanently reduce bank indebtedness (see note 15).

The Company has provided a first floating charge over all the assets and a limited recourse guarantee from Paramount Oil and Gas Ltd., a related entity with a significant ownership interest in the Company. The facility bears interest at prime rates, bankers' acceptance rates or LIBOR rates plus a margin ranging from 250 to 800 basis points. On October 1, 2002, the margins increased by 50 basis points and increased by the same amount on the first day of each month thereafter. There are no contractual repayment requirements under this facility.

As at December 31, the following amounts were drawn under this facility:

	2002	2001
Production/working capital facility – current interest rate of 7.5%	\$ 418,570	\$ –
Bridge facility – current interest rate of 13%	44,900	–
LIBOR advances – current interest rate of 7.75% (2001 – 3.2%)	31,556	31,914
Wilson Drilling bank loan – current interest rate of 5.5%	3,071	–
Bankers' acceptances – 30 day average rate of 5.25% in 2001	–	282,234
	\$ 498,097	\$ 314,148

The Company has an office building which was acquired as a result of the acquisition of Summit Resources Limited. The building is mortgaged at an interest rate of 6.15 percent over a term of five years ending December 31, 2007.

The Company has letters of credit totaling \$13.3 million outstanding with a Canadian Chartered Bank. These letters of credit reduce the amount available under the Company's existing credit facility.

7. RELATED PARTY TRANSACTIONS

The Company has an unsecured note payable in the amount of \$33 million (2001 – nil) to Paramount Oil and Gas Ltd. The note bears interest at bank prime plus 1 percent, and is repayable upon closing of a proposed rights offering by Paramount Energy Trust (see note 15). The effective interest rate on the note during 2002 was 5.5 percent.

8. SHARE CAPITAL

(a) authorized capital

The authorized capital of the Company consists of an unlimited number of non-voting preferred shares without nominal or par value, issuable in series, and an unlimited number of common shares without nominal or par value.

(b) issued capital

Common Shares	Number	Consideration
Balance December 31, 2000 and 2001	59,453,600	\$ 189,320
Stock options exercised during the year	5,000	72
Expenses recognized in respect of stock-based compensation during the year	–	801
Balance December 31, 2002	59,458,600	\$ 190,193

The Company instituted a Normal Course Issuer Bid to acquire a maximum of 5 percent of its issued and outstanding shares commencing September 1, 2001, and ending August 31, 2002. During 2002 and 2001, no shares were purchased pursuant to the plan.

Notes to the Consolidated Financial Statements

(c) stock option plan/share appreciation rights plan

During 2001, the Company replaced the Share Appreciation Rights Plan ("SARP") with an employee stock option plan. Under the plan, stock options are granted at the current market price on the date of issuance. Options granted vest over four years and have a four-and-a-half year contractual life. Share appreciation rights previously held by employees will be grandfathered until their expiry on January 31, 2004, and will be capped at a price of \$14.50, that being the grant price of an equal number of stock options. Under the SARP, participants are entitled to receive a benefit of an amount equal to the positive difference between the exercise price and \$14.50, which difference will be charged to general and administrative expenses. At December 31, 2002, 238,000 SARPs remained outstanding (December 31, 2001 – 479,000 SARPs). During 2002, 177,000 SARPs were exercised at a cost of \$0.6 million (2001 – 329,500 SARPs, \$1.7 million), which amount is charged to general and administrative expenses.

As at December 31, 2002, 5.9 million stock options were reserved for issuance under the Company's Employee Incentive Stock Option Plan, of which 1.9 million shares are outstanding, exercisable to September 30, 2006, at prices ranging from \$12.00 to \$16.50 per share.

SARPs/Stock options	2002		2001	
	Average grant price	Rights/ options	Average grant price	Rights/ options
Balance, beginning of year	\$ 14.08	2,173,500	\$ 12.72	1,184,500
Granted	15.90	80,000	14.33	1,694,500
Exercised	12.98	(195,000)	14.93	(329,500)
Cancelled	14.23	(109,000)	14.16	(376,000)
Balance, end of year	\$ 14.25	1,949,500	\$ 14.08	2,173,500
SARPs/Options exercisable, end of year	\$ 14.35	738,500	\$ 13.23	213,500

The following summarizes information about stock options/SARPs outstanding at December 31, 2002:

Year of grant	Number outstanding at December 31, 2002	Weighted average contractual life (years)	Weighted average exercise price/share	Number exercisable at December 31, 2002	Weighted average exercise price/share
2002	80,000	4	\$ 15.90	-	-
2001	1,631,500	3	\$ 14.35	618,000	\$ 14.55
2000	167,000	2	\$ 13.00	55,500	\$ 13.00
1999	56,000	2	\$ 14.00	50,000	\$ 14.00
1998	15,000	1	\$ 12.00	15,000	\$ 12.00
	1,949,500		\$ 14.25	738,500	\$ 14.35

Notes to the Consolidated Financial Statements

9. INCOME TAXES

The income tax provision differs from the expected income taxes obtained by applying the Canadian corporate tax rate to income before taxes as follows:

	2002	2001
Corporate tax rate	42.14%	43.18%
Calculated income tax (recovery) expense	\$ (11,571)	\$ 87,528
Increase (decrease) resulting from:		
Non-deductible Crown charges, net of Alberta Royalty Tax Credit	10,449	41,394
Federal resource allowance	(29,958)	(45,215)
Provincial income tax rate adjustment	(2,758)	(8,842)
Large Corporation Tax and other	9,150	2,729
Non-taxable portion of gain on sale of investments	(8,603)	-
Other	(4,474)	6,210
Income tax (recovery) expense	\$ (37,765)	\$ 83,804

Components of Future Income Taxes

The net future tax liability comprises:	2002	2001
Differences between tax base and reported amounts of depreciable assets	\$ 285,201	\$ 217,617
Share issue costs	(155)	(190)
Provision for future site restoration	(7,255)	(2,867)
Deferred hedging loss	-	5,648
Other	2,064	1,665
	\$ 279,855	\$ 221,873

As at December 31, 2002, the Company has tax pools of approximately \$796.3 million (2001 - \$562.1 million) available for deduction against future taxable income.

10. SURMONT COMPENSATION

During 2000, the Alberta Energy and Utilities Board issued a decision regarding the Surmont natural gas/bitumen co-production issue. As a result of this decision, the Board ordered the shut-in of approximately 22 MMcf/d of the Company's production. On February 28, 2002, the Company and the Surmont Gas Producers entered into a Memorandum of Agreement with the Province of Alberta effective May 1, 2000. The Memorandum provided for compensation of approximately \$85 million to be paid to the Surmont Gas Producers by the Alberta Crown in the form of reduced royalties, as well as the granting to the Province of Alberta by the Surmont Gas Producers of an 11 percent gross overriding royalty encompassing certain wells, land and leases affected by the shut-in order of May 1, 2000.

In June 2002, the Company received approximately \$47 million in the form of reduced royalties from the Province of Alberta as compensation for its proportionate share of the settlement. The cash settlement, net of the net book value of wells, lands and leases in the affected area of approximately \$9 million, has been recorded in net earnings in the current period.

11. FINANCIAL INSTRUMENTS

The Company's financial instruments included in the Consolidated Balance Sheet consist of cash, short-term investments, accounts receivable, accounts payable and accrued liabilities, shareholder loan, bank loan, mortgage and drilling rig indebtedness.

(a) foreign exchange hedges

The Company has entered into the following currency index swap transactions, fixing the exchange rate on receipts of

Notes to the Consolidated Financial Statements

US \$40.9 million for CDN \$58.6 million over the next three years at CDN \$1.4322. The US \$/CDN \$ closing exchange rate was 1.5776 as at December 31, 2002 (December 31, 2001 - 1.5928).

Year of settlement	US dollars	Weighted average exchange rate
2003	\$ 16,570	1.4302
2004	\$ 12,360	1.4333
2005	\$ 12,000	1.4337
	\$ 40,930	1.4322

At December 31, 2002, the estimated fair value of these hedges based on the Company's assessment of available market information was a loss of \$6.0 million (2001 - loss of \$4.6 million).

(b) natural gas commodity price hedges

At December 31, 2002, the Company has entered into financial forward sales arrangements as follows:

AECO	Price	Term
10,000 GJ/d	\$ 5.46	November 2002 - October 2003
20,000 GJ/d	\$ 5.06	November 2002 - October 2003
20,000 GJ/d	\$ 5.25	November 2002 - October 2003
NYMEX		
20 MMcf/d	US \$ 3.83	November 2002 - October 2003
20 MMcf/d	US \$ 3.90	November 2002 - October 2003
10 MMcf/d	US \$ 4.10	November 2002 - October 2003
WTI		
1,000 Bbl/d	US \$ 24.07	May 2002 - April 2004
1,000 Bbl/d	US \$ 24.33	January 2003 - December 2003

Had these financial contracts been settled on December 31, 2002, using prices in effect at that time, the mark-to-market before-tax loss would have totaled \$28.7 million.

During 2002, \$46.8 million of net gains related to commodity hedging contracts (2001 - \$15.8 million net gains) are included in petroleum and natural gas sales.

(c) fair values of financial assets and liabilities

Borrowings under bank credit facilities and the issuance of commercial paper are for short periods and are market rate based; thus, carrying values approximate fair value. Fair values for derivative instruments are determined based on the estimated cash payment or receipt necessary to settle the contract at year-end. Cash payments or receipts are based on discounted cash flow analysis using current market rates and prices available to the Company.

The fair values of other financial instruments, including cash, accounts receivable, accounts payable and accrued liabilities, shareholder loan and bank loans, approximate their carrying values due to the short-term maturity of those instruments.

The fair values of the mortgage and drilling rig indebtedness approximate their carrying values, as there have been no significant changes in long-term interest rates from the dates these liabilities were incurred to the balance sheet date.

(d) credit risk

The Company is exposed to credit risk from financial instruments to the extent of non-performance by third parties, and non-performance by counterparties to swap agreements. The Company minimizes credit risk associated with possible non-performance by financial instrument counterparties by entering into contracts with only highly rated counterparties; and controls third-party credit risk with credit approvals, limits on exposures to any one counterparty, and monitoring procedures. The Company sells production to a variety of purchasers under normal industry sale and payment terms. The Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal credit risks.

Notes to the Consolidated Financial Statements

12. CHANGE IN NON-CASH WORKING CAPITAL

	2002	2001
Change in non-cash working capital:		
Short-term investments	\$ (236)	\$ 11,257
Accounts receivable	(18,686)	37,137
Prepaid expenses	(5,893)	(4,862)
Deferred hedging loss	17,638	(17,638)
Accounts payable and accrued liabilities	48,312	(47,641)
Less working capital deficiency acquired (note 2)	(7,950)	—
	\$ 33,185	\$ (21,747)
Operating activities	\$ 40,145	\$ (17,677)
Investing activities	(6,960)	(4,070)
	\$ 33,185	\$ (21,747)

Amounts paid during the year related to interest and large corporations and other taxes were as follows:

	2002	2001
Interest paid	\$ 23,278	\$ 19,135
Large corporations and other taxes paid	\$ 20,447	\$ 2,729

13. CONTINGENCIES

The Company is party to various legal claims associated with the ordinary conduct of business. The Company does not anticipate that these claims will have a material impact on the Company's financial position.

14. GAIN ON SALE OF INVESTMENTS

During the year, the Company recorded gains on disposal of its investments in Peyto Exploration and Development Corp. and other short-term investments of \$40.8 million.

15. SUBSEQUENT EVENTS

(a) On February 3, 2003, the Company transferred to Paramount Energy Trust (the "Trust") assets in the Legend area of Northeast Alberta for proceeds of \$81 million, including 9,907,767 Trust units and a \$30 million note payable.

(b) On February 3, 2003, the Company declared a dividend-in-kind of an aggregate 9,907,767 Trust units. The dividend was paid to holders of the Company's common shares of record on the close of business February 11, 2003.

(c) In March 2003, the Company disposed of a significant portion of its Northeast Alberta natural gas properties to the Trust, the major unit holder of which is also a major shareholder of the Company. The Company received net proceeds on disposition of \$209 million, which proceeds were used to reduce bank indebtedness.

As a result of the disposition, the Company's borrowing base on its credit facility was reduced to \$315.5 million.

16. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform with the current year's financial statement presentation.

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INCORPORATION

Paramount Resources Ltd. ("Paramount" or the "Company") was incorporated under the laws of the Province of Alberta on February 14, 1978. The Company commenced operations as a public company listed on the Alberta Stock Exchange on December 18, 1978, with a successful Initial Public Offering that raised \$4.7 million and a share exchange with a private company, Paramount Oil & Gas Ltd., for certain crude oil and natural gas assets with book value of \$341,000.

On November 30, 1984, Paramount was listed on The Toronto Stock Exchange (TSX) and is part of the S&P/TSX Composite Index (Oil & Gas Producers sub index).

The head and principal office of the Company is located at Suite 4700, 888 Third Street S. W., Calgary, Alberta T2P 5C5.

MANAGEMENT OF THE COMPANY

The management of the Company is provided by ten officers, two of whom currently also serve as directors. There are nine non-management directors to complete the Board of Directors. The names, municipality of residence, position with Paramount and principal occupation of each of the officers and directors can be found in the Management Information and Proxy Circular dated March 19, 2003.

The term of office for each director of the Company is from the date of the annual meeting at which the director is elected or appointed until the annual meeting next following or until his successor is elected or appointed. The current Board of Directors was nominated and elected at the Annual Meeting of the Shareholders held on June 20, 2002. The Board of Directors has an Audit Committee which consists of Messrs. Gorman, Roy and MacInnes; a Compensation Committee which consists of Messrs. C. H. Riddell, Roy and Wylie; and an Environmental Committee which consists of Messrs. MacInnes, Roy and Wylie.

As at December 31, 2002, the directors and officers of the Company as a group beneficially owned 31,978,795 common shares, representing 53.78 percent of the 59,458,600 issued and outstanding common shares of Paramount Resources Ltd.

The 2003 Annual General Meeting will be held on June 26, 2003 in Calgary, Alberta.

DESCRIPTION AND DEVELOPMENT OF BUSINESS

Paramount Resources Ltd. is a Canadian natural resource company involved in the exploration, development and production of petroleum and natural gas, primarily in Alberta but also in British Columbia, Saskatchewan, the Northwest Territories, California, Montana, North Dakota and Wyoming. In 2002, sales of natural gas accounted for approximately 81 percent of the Company's total production.

The Company's ongoing exploration, development and production activities are designed to establish new reserves of oil and natural gas and increase the productive capacity of existing fields. In order to optimize its net capacity and control costs, the Company increases ownership and throughput in existing plants as economic opportunities arise and occasionally disposes of lower working interest properties. Paramount strives to maintain a balanced portfolio of opportunities, increasing its working interest in low to medium risk projects and entering into joint venture arrangements on select high risk/high return exploration prospects.

Paramount also participates in the petroleum and natural gas industry through the focused acquisition of petroleum and natural gas assets within established core areas. This acquisition strategy focuses on long-term value including assets which will increase Paramount's current working interest. To take advantage of opportunities as they arise, the Company maintains a strong balance sheet which allows such acquisitions to be financed.

At December 31, 2002, approximately 85 percent of Paramount's proved and probable natural gas reserves were located in Alberta with the balance in Montana, North Dakota, British Columbia, the Northwest Territories and Saskatchewan. Oil and natural gas liquids reserves are 60 percent located in Alberta, with the remainder in Saskatchewan, the Northwest Territories, North Dakota and Montana. In 2002, Paramount operated 75 percent of its producing natural gas wells and approximately 60 percent of its producing crude oil wells.

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Paramount has established core areas of production in Kaybob, Sturgeon Lake/Mirage, Northwest Alberta, Liard/Northeast British Columbia and Southern Alberta/Southeast Saskatchewan/ Montana/North Dakota. Paramount is continuing to explore actively for petroleum and natural gas reserves in Central and Northwest Alberta, Northeast British Columbia, Southeast Saskatchewan, the Northwest Territories, Montana and North Dakota. The Company has also established opportunities for heavy oil exploration and development in Northeast Alberta. The development of new core areas ensures adequate supply for existing gas markets and contracts, and is accelerated within the limits of the Company's cash resources when markets are sufficient to support additional supply.

MAJOR EVENTS

a) Subsequent Events

On May 12, 2002, Paramount announced its intention to create a new royalty trust that would hold substantially all of Paramount's Northeast Alberta natural gas assets. The following transactions were completed in the first quarter 2003:

1. On February 3, 2003, Paramount transferred to the Paramount Energy Trust ("PET" or "Trust") assets in the Legend area of Northeast Alberta for proceeds of \$81 million, including 9,907,767 units of the Trust and a \$30 million note payable.
2. On February 3, 2003, Paramount declared a dividend-in-kind of an aggregate of 9,907,767 trust units of PET. The dividend was paid to holders of Paramount common shares of record on the close of business on February 11, 2003. The dividend was declared after PET received all regulatory clearances with respect to its final prospectus in Canada and its registration statement in the United States. The final prospectus and registration statement qualified and registered (i) the Dividend Trust Units, (ii) Rights to purchase further Trust Units, which Rights were issued to unitholders after the payment of the Dividend, and (iii) the Trust Units issuable upon the exercise of the Rights.
3. On March 11, 2003, in conjunction with the closing of a rights offering by the Trust, Paramount disposed of additional assets in Northeast Alberta to Paramount Operating Trust for total consideration of \$220 million. The combined production of natural gas including the assets in the Legend area averaged 97 MMcf/d during 2002.

The closing of the above transactions in the first quarter 2003 represent the completion of the formation and structuring of Paramount Energy Trust.

b) Acquisitions

Effective June 28, 2002, Paramount acquired all the issued and outstanding shares of Summit Resources Limited for a total consideration of \$338.4 million including net debt. The acquisition increased the Corporation's proven and probable oil and natural gas liquids reserves at January 1, 2003, by 11.9 MMBbl and proven and probable natural gas reserves by 91 Bcf. Production was increased by approximately 5,000 Bbl/d of oil and natural gas liquids and 50 MMcf/d of natural gas.

c) Capital Transactions

Since inception, the Company has raised share capital in public markets on four occasions. In addition, the shares of Paramount have split twice on a three-for-one basis. As at December 31, 2002, the Company had 59,458,600 shares outstanding with an indicated market capitalization of \$892 million based upon the December 31, 2002, \$15.00 per share closing price on the Toronto Stock Exchange. Following is a summary of capital transactions the Company has completed in the past five years.

1. On October 8, 1999, Paramount issued 2.5 million common shares at an average price of \$21.87 per share pursuant to a private placement flow-through share offering for gross proceeds of \$54.7 million. Proceeds from the issue were used to fund the 1999-2000 capital expenditure program.
2. On November 13, 1998, Paramount issued 3.0 million common shares at a price of \$15.00 per share for gross proceeds of \$45.0 million pursuant to a prospectus dated November 4, 1998. Proceeds were initially used to reduce bank indebtedness.

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COMPETITIVE CONDITIONS

The petroleum and natural gas industry is highly competitive. Paramount competes with numerous other participants in the search for and acquisition of crude oil and natural gas properties and in the marketing of these commodities. Successful reserve replacement in the future will depend not only on the further development of present properties, but also on the ability to select and acquire suitable prospects for exploratory drilling and development.

Paramount has firm service for most of its natural gas production as opposed to interruptible allocations on pipeline systems. The Company closely monitors the daily production from all of its plants ensuring that contractual obligations will be met. Balancing contractual commitments, natural gas sales are directed to those markets where the Company believes prices will be best.

ENVIRONMENTAL PROTECTION

Paramount has in place an Environmental Committee of the Board of Directors comprised of three non-management directors of the Company. The tenet of the Company's Environmental Policy is as follows:

Paramount Resources Ltd. "Paramount" is committed to protecting the environment, to maintaining public health and safety, and to compliance with all applicable environmental laws, regulations and standards. Paramount will do all that it reasonably can to ensure that sound environmental practices are followed in all of its operations and activities.

The Committee is guided by a specific set of principles to ensure that this policy is supported. These principles apply to all employees of Paramount and are designed to make certain that all applicable environmental laws, regulations and standards are complied with. The Company monitors all activities and makes reasonable efforts to ensure that companies who provide services to Paramount will operate in a manner consistent with its environmental policy.

In recognition of its Environmental and Safety Policies and to demonstrate continual improvement in its performance, Paramount has been awarded the Canadian Association of Petroleum Producers' ("CAPP") Gold Level Certificate for Stewardship participation, the Silver Champion Level Reporter Recognition level from Canada's Climate Change Voluntary Challenge and Registry Inc. and the Alberta Human Resources and Employment Certificate of Recognition for its safety management program. Paramount is also registered in the Workers' Compensation Board 'Partners in Injury Reduction' ("PIR") program. Paramount has systems and procedures in place to manage its safety and environmental affairs effectively and to meet regulatory compliance.

HUMAN RESOURCES

At January 1, 2003 Paramount had 152 full time head office employees and 128 full time employees at field locations. The Company's compensation of full time employees includes a combination of salary, benefits and participation in either a stock option plan or a company-assisted share purchase savings plan. Shares under the savings plan are purchased in the marketplace by the plan trustee.

LAND

The following table sets forth Paramount's land position at December 31, 2002. The Company's holdings total 7,675 gross (5,077 net) acres. Approximately 72 percent of the Company's gross land holdings are considered undeveloped, and approximately 47 percent of the undeveloped land is located in Alberta.

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LAND (CONTINUED)

(thousands of acres)	2002		2001		2000		1999		1998	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Undeveloped Land										
Alberta	2,581	1,884	2,138	1,524	2,100	1,475	1,950	1,388	1,789	1,178
British Columbia	248	164	248	163	178	101	191	105	138	73
Saskatchewan	21	15	6	1	7	1	199	39	238	44
Northwest Territories	843	580	845	580	795	523	494	221	509	220
Montana, North Dakota	149	70	—	—	—	—	—	—	—	—
Other	1,664	832	1,664	1,497	1,664	1,497	—	—	—	—
Subtotal	5,506	3,545	4,901	3,765	4,744	3,597	2,834	1,753	2,674	1,515
Acreage assigned reserves										
Alberta	2,027	1,461	1,592	1,170	1,408	1,008	1,446	1,027	1,280	866
British Columbia	32	10	8	3	3	1	17	9	16	9
Saskatchewan	12	6	1	0*	—	—	16	4	15	40
Northwest Territories	74	45	74	45	61	42	60	41	45	3
Montana, North Dakota	24	10	—	—	—	—	—	—	—	—
Subtotal	2,169	1,532	1,675	1,218	1,472	1,051	1,539	1,081	1,356	918
Total Acres	7,675	5,077	6,575	4,984	6,216	4,648	4,373	2,834	4,030	2,433

* Net acreage assigned reserves in Saskatchewan less than 1,000 acres.

- (1) "Gross" acres means the total acreage in which Paramount has a working interest, or a royalty interest that may be converted to a working interest.
- (2) "Net" acres means the number of acres obtained by multiplying the gross acres by Paramount's working interest therein.

DRILLING HISTORY

The following table summarizes the results of Paramount's drilling activity for each of the last five fiscal years. The working interest in certain of these wells may change after payout.

	2002		2001		2000		1999		1998	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells⁽³⁾										
Gas	76	56.3	101	84.4	37	27.0	50	41.9	50	36.3
Oil	5	3.1	7	6.1	9	5.8	8	4.0	10	3.9
Standing/service	1	1.0	—	—	2	1.3	1	0.5	5	3.8
Dry	7	4.0	4	3.5	2	2.0	3	2.0	4	3.5
Subtotal	89	64.4	112	94.0	50	36.1	62	48.4	69	47.5
Exploratory Wells⁽⁴⁾										
Gas	38	27.4	66	52.6	88	71.6	42	31.3	59	38.1
Oil	4	3.6	5	4.2	2	0.5	1	0.3	13	2.9
Standing/service	—	—	1	0.5	—	—	2	0.4	6	3.6
Dry	4	4.0	12	7.4	23	20.5	7	5.7	25	11.8
Subtotal	46	35.0	84	64.7	113	92.6	52	37.7	103	56.4
Total Wells	135	99.4	196	158.7	163	128.7	114	86.1	172	103.9

- (1) "Gross" wells means the number of wells in which Paramount has a working interest or a royalty interest that may be converted to a working interest.
- (2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Paramount's percentage working interest therein.
- (3) "Development" well is a well drilled within or in close proximity to a discovered pool of petroleum or natural gas.
- (4) "Exploratory" well is a well drilled either in search of a new and as yet undiscovered pool of petroleum or natural gas or with the expectation of significantly extending the limit of a pool that is partly discovered.

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OIL AND NATURAL GAS WELLS

As at December 31, 2002, Paramount had an interest in 3,083 gross (2,059.0 net) producing and non-producing oil and natural gas wells as follows:

As at December 31, 2002	Producing		Non-producing ⁽¹⁾	
	Gross ⁽²⁾	Net ⁽³⁾	Gross	Net
Crude oil wells				
Alberta	282	168.7	122	70.8
Saskatchewan	133	66.0	34	15.6
Northwest Territories	—	—	7	5.6
Montana	38	25.7	5	3.5
North Dakota	59	25.0	10	3.9
Wyoming	—	—	1	0.8
Subtotal	512	285.4	179	100.2
Natural gas wells				
Alberta	1,335	958.9	937	672.9
British Columbia	24	8.8	17	8.8
Saskatchewan	1	—	1	0.3
Northwest Territories	12	7.1	23	13.3
Montana	23	1.8	15	1.1
North Dakota	1	—	—	—
California	1	0.1	2	0.3
Subtotal	1,397	976.7	995	696.7
Total	1,909	1,262.1	1,174	796.9

- (1) "Non-producing" wells are wells which Paramount considers capable of production but which, for a variety of reasons including but not limited to a lack of markets and lack of development, cannot be placed on production at the present time.
- (2) "Gross" wells means the number of wells in which Paramount has a working interest or a royalty interest that may be convertible to a working interest.
- (3) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Paramount's percentage working interest therein.

RESERVES

The majority of Paramount's assigned reserves of crude oil, natural gas liquids, and natural gas are located in western Canada, with the remaining reserves in the United States; specifically Montana and North Dakota. For 2002, all reserves were determined through independent engineering evaluations completed by McDaniel & Associates Consultants Ltd. ("McDaniel"), Sproule Associates Limited, and Sproule Associates Inc. Their reports were prepared effective January 1, 2003.

The following table details Paramount's working interest share of reserves, net reserves after royalties, and present worth values as at December 31, 2002.

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RESERVES (CONTINUED)

December 31, 2002 Reserve Summary	Gross (Bcf)	Net (Bcf)	Present Worth Value (before tax, \$ millions)			
			0%	10%	12%	15%
Natural gas reserves						
Proved producing	344.2	272.5	925.1	686.3	654.9	613.9
Proved nonproducing	75.7	63.2	116.8	69.7	64.1	57.1
Proved undeveloped	26.6	23.4	69.7	28.1	24.6	20.5
Total proved	446.5	359.1	1,111.6	784.1	743.6	691.5
Probable additional	172.1	131.8	477.8	227.8	202.5	172.1
50% reduction for risked probable reserves	(86.0)	(65.9)	(238.9)	(113.9)	(101.3)	(86.0)
Risked probable additional	86.1	65.9	238.9	113.9	101.2	86.1
Total risked natural gas reserves	532.6	425.0	1,350.5	898.0	844.8	777.6
	MBbl	MBbl	0%	10%	12%	15%
Crude oil and natural gas liquids reserves						
Proved producing	14,677.1	12,251.3	237.4	165.7	157.1	146.2
Proved nonproducing	1,858.3	1,609.9	36.5	21.7	20.2	18.4
Proved undeveloped	1,009.9	934.7	18.5	11.3	10.4	9.3
Total proved	17,545.3	14,795.9	292.4	198.7	187.7	173.9
Probable additional	5,300.5	4,645.1	93.2	47.2	42.6	37.0
50% reduction for risked probable reserves	(2,650.3)	(2,322.5)	(46.6)	(23.6)	(21.3)	(18.5)
Risked probable additional	2,650.2	2,322.6	46.6	23.6	21.3	18.5
Total risked crude oil and natural gas liquids reserves	20,195.5	17,118.5	339.0	222.3	209.0	192.4

The Company's five-year summary of reserves is outlined in the following tables. Probable reserves reported in the tables below have been arbitrarily reduced by 50 percent to account for risk.

Natural gas reserves (Bcf)	2002	2001	2000	1999	1998
Gross before royalties					
Proved producing	344.2	298.9	338.5	370.9	412.8
Proved non-producing, proved undeveloped	102.3	138.8	179.6	223.8	194.5
Total proved	446.5	437.7	518.1	594.7	607.3
Probable additional	172.1	126.0	139.3	155.1	180.9
Total proved and probable	618.6	563.7	657.4	749.8	788.2
50% reduction for risked probable reserves	(86.0)	(63.0)	(69.6)	(77.5)	(90.5)
Total risked reserves	532.6	500.7	587.8	672.3	697.7
Net after royalties					
Proved producing	272.5	234.8	265.3	284.0	318.8
Proved non-producing, proved undeveloped	86.6	118.6	155.1	192.7	173.4
Total proved	359.1	353.4	420.4	476.7	492.2
Probable additional	131.8	103.6	113.4	127.7	150.3
Total proved and probable	490.9	457.0	533.8	604.4	642.5
50% reduction for risked probable reserves	(65.9)	(51.8)	(56.7)	(63.8)	(75.2)
Total risked reserves	425.0	405.2	477.1	540.6	567.3

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RESERVES (CONTINUED)

Crude oil & liquids reserves (MBbl)

Gross before royalties					
Proved producing	14,677.1	5,063.0	4,290.0	3,231.1	5,018.0
Proved non-producing, proved undeveloped	2,868.2	1,276.0	419.0	3,032.8	2,877.0
Total proved	17,545.3	6,339.0	4,709.0	6,263.9	7,895.0
Probable additional	5,300.5	1,628.0	1,271.0	2,616.0	3,735.0
Total proved and probable	22,845.8	7,967.0	5,980.0	8,879.9	11,630.0
50% reduction for risked probable reserves	(2,650.3)	(814.0)	(635.5)	(1,308.0)	(1,867.5)
Total risked reserves	20,195.5	7,153.0	5,344.5	7,571.9	9,762.5
Net after royalties					
Proved producing	12,251.3	4,037.0	3,325.0	2,569.3	4,102.0
Proved non-producing, proved undeveloped	2,544.6	1,058.0	292.0	2,303.7	2,109.0
Total proved	14,795.9	5,095.0	3,617.0	4,873.0	6,211.0
Probable additional	4,645.1	1,411.0	1,106.0	2,134.6	3,053.0
Total proved and probable	19,441.0	6,506.0	4,723.0	7,007.6	9,264.0
50% reduction for risked probable reserves	(2,322.5)	(706.0)	(553.0)	(1,067.3)	(1,526.5)
Total risked reserves	17,118.5	5,800.0	4,170.0	5,940.3	7,737.5

RESERVE RECONCILIATION

The table below sets forth Paramount's reconciliation of gross proved and probable reserves from January 1, 2002 to January 1, 2003, using escalated prices and costs. The probable reserves have been reduced by 50 percent to account for risk.

Natural gas reserves (Bcf)

	Proved	Probable	Total
Risk discounted balance at January 1, 2002	437.7	63.0	500.7
Revisions of previous estimates	(9.7)	19.0	9.3
Extensions and discoveries	30.5	8.8	39.3
Acquisitions of gas in place	76.1	18.3	94.4
Dispositions of gas in place	-	-	-
Production estimate	(88.1)	-	(88.1)
50% reduction for risked probable reserves	-	(23.0)	(23.0)
Balance at January 1, 2003	446.5	86.1	532.6

Crude oil and liquids (MBbl)

	Proved	Probable	Total
Risk discounted balance at January 1, 2002	6,339.0	814.0	7,153.0
Revisions of previous estimates	1,244.3	395.8	1,640.1
Extensions and discoveries	1,012.0	367.0	1,379.0
Acquisitions of crude oil/liquids in place	11,017.0	2,910.0	13,927.0
Dispositions of crude oil/liquids in place	-	-	-
Production estimate	(2,067.0)	-	(2,067.0)
50% reduction for risked probable reserves	-	(1,836.6)	(1,836.6)
Balance at January 1, 2003	17,545.3	2,650.2	20,195.5

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The following table sets forth Paramount's reconciliation of gross natural gas reserves for each of the past five years.

Natural gas reserves (Bcf)	2002	2001	2000	1999	1998
Opening balance	500.7	587.8	672.3	697.8	559.2
Revisions of previous estimates	9.3	(57.6)	(85.1)	(96.3)	71.0
Extensions and discoveries	39.3	40.1	59.8	99.4	100.1
Acquisitions of gas in place	94.4	5.9	29.0	38.8	64.9
Dispositions of gas in place	-	-	(14.0)	-	(16.9)
Production estimate	(88.1)	(82.0)	(82.0)	(80.3)	(67.7)
50% reduction for risked probable reserves	(23.0)	6.5	7.8	12.9	(12.8)
Closing balance	532.6	500.7	587.8	672.3	697.8

The following definitions form the basis of classification for reserves presented in the McDaniel report:

1. "*Proved Reserves*" are those reserves estimated as recoverable under current technology and existing economic conditions from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to the Company's reserves in the area.

i) *Proved Producing Reserves*

Those proved reserves that are actually on production, or if not producing, that could be recovered from existing wells or facilities and where the reasons for the current non-producing status is the choice of the owner. An illustration of such a situation is where a well or zone is capable but is shut-in because its deliverability is not required to meet contract commitments. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to the Company's reserves in the area.

ii) *Proved Non-Producing Reserves*

Those non-producing proved reserves recoverable from existing wells that require relatively minor capital expenditures to produce.

iii) *Proved Undeveloped Reserves*

Those reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major capital expenditure will be required.

2. "*Probable Additional Reserves*" are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

3. "*Gross Reserves*" are defined as the reserves owned before deduction of any royalties.

4. "*Net Reserves*" are defined as the gross reserves of the properties in which an interest is held, less all royalties and interests owned by others.

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MAJOR PRODUCING PROPERTIES

The following table summarizes average production volumes from Paramount's major producing properties, for each of the last five fiscal years.

Natural Gas

(MMcfd)	2002	2001	2000	1999	1998
Northeast Alberta - East Side					
Bohn Lake	2.6	3.4	3.8	4.8	—
Chard	2.3	2.4	2.7	3.5	4.2
Clyde	2.8	3.0	2.8	2.2	2.5
Cold Lake	9.5	11.9	14.4	17.1	13.3
Corner	13.9	15.5	15.1	20.3	25.2
Kettle River	4.5	5.5	10.9	24.9	24.8
Leismer	9.5	11.2	8.0	3.5	3.1
Quigley	3.3	3.0	5.0	10.1	11.6
Thornbury	4.5	4.9	6.1	6.9	6.8
Winefred	4.6	5.5	6.9	7.1	6.5
Other	0.6	0.8	1.1	4.8	4.8
Subtotal	58.1	67.1	76.8	105.2	102.8
Northeast Alberta - West Side					
East Legend	3.9	4.7	4.5	—	—
East Liege	2.2	3.1	4.2	5.7	—
Legend	19.4	17.3	14.0	14.1	14.6
North Liege	2.8	3.3	3.8	4.6	6.3
South Liege	4.3	5.2	5.8	9.0	9.3
Saleski	4.0	4.1	4.6	5.7	6.7
Teepee Creek	1.7	2.7	5.3	9.3	10.7
Other	0.5	1.2	—	—	—
Subtotal	38.8	41.6	42.2	48.4	47.6
Kaybob*					
Clover	3.9	0.3	—	—	—
Fox Creek	4.9	2.5	1.5	—	—
Kakwa	1.1	—	—	—	—
Kaybob	12.2	18.8	18.5	9.8	6.5
Kaybob North	36.5	30.7	31.0	24.5	13.2
Pine Creek	9.7	7.5	7.3	4.9	—
Tony North	3.6	1.8	—	—	—
Two Creeks	2.7	—	—	—	—
Other	12.9	3.7	2.3	8.4	7.4
Subtotal	87.5	65.3	63.7	47.6	27.1
Sturgeon Lake/Mirage*					
Mirage	2.9	—	—	—	—
Saddle Hills	0.8	—	—	—	—
Sturgeon Lake	1.9	—	—	—	—
Other	1.4	3.1	—	—	—
Subtotal	7.0	3.1	—	—	—
Northwest Alberta					
Assumption	1.5	2.7	2.8	—	—
Bistcho Lake	8.3	9.5	10.7	10.0	8.0
Cameron Hills	9.0	—	—	—	—
Negus East	4.3	6.7	4.8	—	—

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Negus West	2.2	3.6	1.9	—	—
Pedigree	4.9	6.1	5.1	3.3	—
Other	0.2	0.6	0.8	0.7	—
Subtotal	30.4	29.2	26.1	14.0	8.0

Liard Basin - Northeast British Columbia/Northwest Territories*

Clarke Lake	3.2	—	—	—	—
Maxhamish/Liard	4.8	5.2	4.6	—	—
Liard Non-Op	1.8	2.5	0.8	—	—
Tattoo	2.5	—	—	—	—
Other	—	1.6	—	—	—
Subtotal	12.3	9.3	5.4	—	—

Southern Alberta/Saskatchewan/Montana/North Dakota*

Chain/Craigmyle	1.8	—	—	—	—
Retlaw	1.3	—	—	—	—
Sylvan Lake	1.0	—	—	—	—
Other	1.3	—	—	—	—
Subtotal	5.4	—	—	—	—

Non-Core	1.9	9.4	5.8	4.8	18.0
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Total	241.4	225.0	220.0	220.0	203.5
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Crude Oil and Liquids

(Bbl/d)

Kaybob*

Fox Creek	101	—	—	—	—
Kakwa	116	—	—	—	—
Kaybob 10-2	162	—	—	—	—
Kaybob	110	171	119	89	84
Kaybob North	900	711	498	218	253
Kaybob West	344	576	274	297	323
Pine Creek	437	265	213	152	138
Other	121	132	154	83	223
Subtotal	2,291	1,855	1,258	839	1,021

Sturgeon Lake/Mirage*

Mirage	182	—	—	—	—
Sturgeon Lake	1,110	—	—	—	—
Sunset	55	—	—	—	—
Other	6	—	—	—	—
Subtotal	1,353	—	—	—	—

Southern Alberta/Saskatchewan/Montana/North Dakota*

Beaver Creek	97	—	—	—	—
Enchant	187	—	—	—	—
Knutson	196	—	—	—	—
Rabbit Hills	129	—	—	—	—
Saskatchewan	534	130	218	852	790
Other	589	—	—	—	—
Subtotal	1,732	130	218	852	790

Liard/NEBC	15	21	95	—	—
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Northwest Alberta	35	—	—	—	—
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Non-Core	237	159	—	163	177
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Total	5,663	2,165	1,571	1,854	1,988
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*six-month production volumes with respect to properties acquired in the Summit acquisition have been averaged over 12 months (annualized).

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The following is a summary of Paramount's major producing properties at December 31, 2002. Paramount's exploration efforts are primarily concentrated in Alberta, British Columbia, Saskatchewan, the Northwest Territories, Montana and North Dakota. In 2002, production from the Northeast Alberta core area accounted for 40 percent of the Company's total natural gas production. Natural gas production from the Company's core area in Kaybob accounted for 36 percent of the total production in 2002. Sturgeon Lake/Mirage, a new core area for the Company resulting mainly from the Summit acquisition, accounted for 3 percent on an annualized basis, with 13 percent from Northwest Alberta, 5 percent from Liard, 2 percent from the new core area at Southern Alberta/Southeast Saskatchewan/Montana/North Dakota, and the remaining 1 percent from non-operated production in non-core areas.

Paramount's natural gas liquids production is from production at the Kaybob core area, Sturgeon Lake/Mirage and Southern Alberta/Southeast Saskatchewan/Montana/North Dakota. The majority of the Company's crude oil production comes from Kaybob (41 percent), Sturgeon Lake (24 percent) and Southern Alberta (31 percent).

Paramount's working interests have been determined before royalties and after deduction of any third party carried interests. Production refers to Paramount's working interest before the deduction of royalties.

Northeast Alberta – East Side – Kettle

These properties are located in the Company's northeasternmost shallow gas production area. The natural gas produced from these facilities is Cretaceous in age at depths up to 450 meters.

Production from this core area was significantly curtailed with the AEUB decision of May 1, 2000, ordering the shut-in of 22 MMcf/d of net gas sales in the Surmont area in which Paramount has a working interest. As a result of this shut-in, the facilities at Chard, Kettle River and Quigley were consolidated into one plant at Kettle River during third quarter 2000 to improve operating efficiencies. The Kettle River property description accounted for the acreage and wells formerly reported separately at Chard and Quigley. Certain of the wells shut in due to the AEUB decision at Surmont have been recompleted in the Clearwater zone and successfully placed back on production. Thus, gas from this region was processed at the Paramount-operated plant at Kettle River, two non-operated plants at Winefred and Surmont where the Company's gas was processed for a custom processing fee, and at a third party-operated plant at Bohn Lake where the Company had a working interest in the facility.

Details relative to each major property and facility are described below.

Kettle River	113,600 gross (102,585 net) acres of land assigned reserves
	29,760 gross (25,190 net) acres undeveloped lands
	105 gross (96.0 net) producing wells
	52 gross (47.2 net) non-producing wells
	Average production net to Paramount in 2002: 10.1 MMcf/d
Winefred	67,840 gross (29,440 net) acres of land assigned reserves
	60,928 gross (22,000 net) acres undeveloped lands
	42 gross (36.7 net) producing wells
	44 gross (38.5 net) non-producing wells
	Average production net to Paramount in 2002: 4.6 MMcf/d
Bohn Lake	46,400 gross (14,272 net) acres of land assigned reserves
	1,600 gross (533 net) acres undeveloped lands
	44 gross (12.8 net) producing wells
	7 gross (1.9 net) non-producing wells
	Average production net to Paramount in 2002: 2.6 MMcf/d

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Northeast Alberta – East Side – Corner

These properties, located in the shallow gas region directly west of Kettle River, produce natural gas from the high deliverability Colony, McMurray and Clearwater reservoirs found in this region of the core area.

The Company owned and operated three facilities at Corner, Leismer, and Clyde Lake at December 31, 2002. Paramount gas was also processed at two outside-operated facilities at Pony and Thornbury for a custom processing fee.

The major producing properties in this area are further detailed below.

Corner	74,240 gross (73,155 net) acres of land assigned reserves
	28,160 gross (27,200 net) acres undeveloped lands
	61 gross (60.4 net) producing wells
	19 gross (18.8 net) non-producing wells
	Average production net to Paramount in 2002: 13.9 MMcf/d
Leismer	114,560 gross (108,078 net) acres of land assigned reserves
	91,520 gross (85,151 net) acres undeveloped lands
	56 gross (51.2 net) producing wells
	79 gross (75.6 net) non-producing wells
	Average production net to Paramount in 2002: 9.5 MMcf/d
Thornbury	48,000 gross (34,252 net) acres of land assigned reserves
	3,200 gross (1,152 net) acres undeveloped lands
	46 gross (33.9 net) producing wells
	22 gross (14.7 net) non-producing wells
	Average production net to Paramount in 2002: 4.5 MMcf/d
Clyde Lake	12,800 gross (11,771 net) acres of land assigned reserves
	14,080 gross (14,080 net) acres undeveloped lands
	13 gross (12.3 net) producing wells
	8 gross (8.0 net) non-producing wells
	Average production net to Paramount in 2002: 2.8 MMcf/d

Northeast Alberta – East Side – Cold Lake

Cold Lake is located south of the aforementioned properties, still in the northeastern shallow gas region and producing from Cretaceous age clastic reservoirs. Gas was processed at two Company-owned plants in this area and at third-party-facilities for a custom processing fee.

The Company also has a 5 to 6 percent net profit interest in approximately 159 heavy oil wells from two different projects in this area.

Cold Lake	96,001 gross (73,223 net) acres of land assigned reserves
	36,160 gross (30,569 net) acres undeveloped lands
	111 gross (91.5 net) producing wells
	73 gross (58.1 net) non-producing wells
	Average production net to Paramount in 2002: 9.5 MMcf/d

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Northeast Alberta – West Side

These properties formed the Company's Northeast Alberta – West Side core area at December 31, 2002. This gas was produced from carbonate reservoirs of Devonian age at depths ranging from 200 to 600 meters as well as from the Cretaceous McMurray and Wabiskaw formations.

The Company produced gas from six facilities in this area, five of which the Company owned and operated; Company-operated facilities included Legend, East Liege, North Liege, South Liege and Saleski. The Company owned 50 percent of the third party-operated plant at Teepee Creek.

These properties are described below.

Legend	106,880 gross (89,514 net) acres of land assigned reserves 24,960 gross (24,422 net) acres undeveloped lands 59 gross (48.1 net) producing wells 20 gross (16.8 net) non-producing wells Average production net to Paramount in 2002: 19.4 MMcf/d
South Liege	85,920 gross (78,891 net) acres of land assigned reserves 31,360 gross (12,163 net) acres undeveloped lands 26 gross (25.2 net) producing wells 47 gross (42.5 net) non-producing wells Average production net to Paramount in 2002: 4.3 MMcf/d
Saleski	65,920 gross (62,342 net) acres of land assigned reserves 22,080 gross (19,424 net) acres undeveloped lands 18 gross (17.2 net) producing wells 12 gross (11.1 net) non-producing wells Average production net to Paramount in 2002: 4.0 MMcf/d
East Legend	27,520 gross (27,520 net) acres of land assigned reserves 24,960 gross (24,960 net) acres undeveloped lands 17 gross (17.0 net) producing wells 8 gross (8.0 net) non-producing wells Average production net to Paramount in 2002: 3.9 MMcf/d
North Liege	69,760 gross (63,333 net) acres of land assigned reserves No undeveloped lands 14 gross (13.3 net) producing wells 23 gross (20.4 net) non-producing wells Average production net to Paramount in 2002: 2.8 MMcf/d
East Liege	10,560 gross (9,471 net) acres of land assigned reserves 640 gross (556 net) acres undeveloped lands 11 gross (10.0 net) producing wells 4 gross (3.7 net) non-producing wells Average production net to Paramount in 2002: 2.2 MMcf/d
Teepee Creek	76,399 gross (39,481 net) acres of land assigned reserves 61,440 gross (46,720 net) acres undeveloped lands 20 gross (10.0 net) producing wells 24 gross (14.0 net) non-producing wells Average production net to Paramount in 2002: 1.7 MMcf/d

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Kaybob

These properties form one of the Company's core areas in Central Alberta and produce gas, oil and natural gas liquids from the Cretaceous Viking, Spirit River, Notikewin and Bluesky/Gething formation as well as the Triassic Montney formation and the Devonian Swan Hills formation.

Paramount operates natural gas plants at Kaybob North, Kaybob, Clover, and Two Creeks and an oil battery at Kaybob West. The Company processes gas from Pine Creek, Clover, Fox Creek, Kaybob South, Pass Creek and Archean at third-party-operated facilities for a fee.

This core area accounted for 36 percent of the Company's total natural gas production in 2002 and 41 percent of the crude oil production.

The major producing facilities are described below. All of the production that came over with the Summit acquisition has been averaged over the total year.

Kaybob North	107,680 gross (92,197 net) acres of land assigned reserves 86,880 gross (69,887 net) acres undeveloped lands 147 gross (128.9 net) producing gas wells 30 gross (21.8 net) non-producing gas wells 26 gross (20.8 net) producing oil wells 22 gross (18.6 net) non-producing oil wells Average production net to Paramount in 2002: 36.5 MMcf/d, 900 Bbl/d
Kaybob	53,120 gross (47,448 net) acres of land assigned reserves 44,160 gross (29,547 net) acres undeveloped lands 58 gross (51.5 net) producing wells 24 gross (21.6 net) non-producing wells Average production net to Paramount in 2002: 12.2 MMcf/d, 110 Bbl/d
Pine Creek	44,480 gross (26,576 net) acres of land assigned reserves 46,080 gross (35,819 net) acres undeveloped lands 55 gross (33.8 net) producing gas wells 17 gross (8.8 net) non-producing gas wells 4 gross (0.3 net) producing oil wells Average production net to Paramount in 2002: 9.7 MMcf/d, 437 Bbl/d
Fox Creek	31,840 gross (16,614 net) acres of land assigned reserves 15,200 gross (11,420 net) acres undeveloped lands 34 gross (20.8 net) producing gas wells 15 gross (8.2 net) non-producing gas wells Average production net to Paramount in 2002: 4.9 MMcf/d, 101 Bbl/d
Clover	14,560 gross (4,656 net) acres of land assigned reserves 1,600 gross (1,280 net) acres undeveloped lands 17 gross (15.7 net) producing gas wells 1 gross (1.0 net) non-producing gas wells 1 gross (0.1 net) non-producing oil wells Average production net to Paramount in 2002: 3.9 MMcf/d, 21 Bbl/d
Kaybob West	3,200 gross (3,200 net) acres of land assigned reserves 640 gross (640 net) acres undeveloped lands 17 gross (17.0 net) producing oil wells 2 gross (2.0 net) non-producing oil wells Average production net to Paramount in 2002: 0.9 MMcf/d, 344 Bbl/d
Kakwa	25,760 gross (3,352 net) acres of land assigned reserves 3,200 gross (1,532 net) acres undeveloped lands 25 gross (3.4 net) producing oil wells 11 gross (3.1 net) non-producing oil wells Average production net to Paramount in 2002: 1.1 MMcf/d, 116 Bbl/d

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Sturgeon Lake / Mirage

This is a new core area for the Company. Paramount acquired the Sturgeon Lake plant and property through the Summit acquisition and another acquisition completed July 1, 2002. Other producing properties gained with the Summit deal are Mirage, Sunset and Valhalla. The Sturgeon Lake property, located in Central Alberta, produces light sour crude oil and liquids rich gas from Devonian Leduc reefs at approximate depths of 9,500 feet. The Mirage property produces light sour crude oil and solution gas from the Upper and Lower Halfway formation at depths of approximately 4,525 feet. Sunset produces oil from Montney reservoirs at depths of about 1,720 feet.

The major producing facilities are described below. Production values for this core area have been annualized.

Sturgeon Lake	21,160 gross (12,884 net) acres of land assigned reserves
	80,440 gross (69,183 net) acres undeveloped lands
	13 gross (4.1 net) producing gas wells
	17 gross (12.6 net) non-producing gas wells
	44 gross (35.9 net) producing oil wells
	20 gross (14.5 net) non-producing oil wells
	Annualized production net to Paramount in 2002: 1.9 MMcf/d, 1,110 Bbl/d
Mirage	11,120 gross (10,213 net) acres of land assigned reserves
	22,240 gross (19,440 net) acres undeveloped lands
	10 gross (9.0 net) producing gas wells
	4 gross (3.6 net) non-producing gas wells
	22 gross (22.0 net) producing oil wells
	5 gross (5.0 net) non-producing oil wells
	Annualized production net to Paramount in 2002: 2.9 MMcf/d, 182 Bbl/d
Sunset	3,680 gross (1,449 net) acres of land assigned reserves
	1,280 gross (753 net) acres undeveloped lands
	11 gross (4.7 net) producing oil wells
	2 gross (0.9 net) non-producing oil wells
	Annualized production net to Paramount in 2002: 55 Bbl/d

Northwest Alberta

The Company has five plants in the Northwest Alberta core area at Bistcho Lake, Cameron Hills, Negus West, Negus East and Assumption. Gas is processed through a third-party-operated plant at Pedigree for a processing fee. Bistcho Lake is located approximately 60 kilometers north of the Zama Lake pipeline terminal. This Company-operated sour gas processing facility at Bistcho Lake produces gas of Middle Devonian age at depths up to 4,950 feet (1,500 meters). The plant at Bistcho Lake also processes gas from a third party-operated field to the south at Larne. Cameron Hills came on production March 29, 2002.

The Negus/Assumption area is east of Rainbow Lake.

The Negus West, Negus East and Assumption Company-operated plants produce gas of Pleistocene age at depths of 30 to 50 meters and Cretaceous gas from the Bluesky/Gething formations at depths from 250 to 300 meters.

The major properties are described below.

Cameron Hills	44,898 gross (39,668 net) acres of land assigned reserves
	40,615 gross (33,928 net) acres undeveloped lands
	6 gross (5.2 net) producing gas wells
	8 gross (7.1 net) non-producing gas wells
	6 gross (5.3 net) non-producing oil wells
	Average production net to Paramount in 2002: 9.0 MMcf/d
Bistcho Lake	52,791 gross (26,941 net) acres of land assigned reserves
	342,064 gross (203,859 net) acres undeveloped lands
	43 gross (22.1 net) producing gas wells
	30 gross (16.4 net) non-producing gas wells
	Average production net to Paramount in 2002: 8.3 MMcf/d, 35 Bbl/d

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Pedigree 25,600 gross (14,174 net) acres of land assigned reserves
80,640 gross (49,376 net) acres undeveloped lands
18 gross (11.9 net) producing gas wells
26 gross (13.4 net) non-producing gas wells
Average production net to Paramount in 2002: 4.9 MMcf/d

Negus East 21,760 gross (18,003 net) acres of land assigned reserves
97,920 gross (94,293 net) acres undeveloped lands
6 gross (5.1 net) producing gas wells
24 gross (20.6 net) non-producing gas wells
Average production net to Paramount in 2002: 4.3 MMcf/d

Negus West 37,760 gross (77,498 net) acres of land assigned reserves
28,671 gross (41,228 net) acres undeveloped lands
22 gross (21.1 net) producing gas wells
36 gross (24.8 net) non-producing gas wells
Average production to Paramount in 2002: 2.2 MMcf/d

Liard Basin, Northeast British Columbia / Northwest Territories

The Company operates two gas plants in northeast British Columbia at Tattoo and Maxhamish.

Maxhamish produces gas of Mississippian age from four wells, three in the Northwest Territories and one in Northeast British Columbia. The Tattoo gas plant, constructed in 2001, produces gas of Mississippian age from two wells in Northeast British Columbia.

Acquired through the Summit acquisition was a non-operated interest in the Clarke Lake natural gas field located ten miles southeast of the city of Fort Nelson in British Columbia. This field is largely winter access only and produces gas from the Upper Devonian Slave Point formation. The Summit acquisition production has been annualized.

Paramount also produces Devonian-age gas from three wells through a non-operated gas plant in the Northwest Territories.

**Maxhamish/
Liard** 16,797 gross (6,462 net) acres of land assigned reserves
486,526 gross (204,474 net) acres undeveloped lands
5 gross (2.3 net) producing gas wells
5 gross (2.0 net) non-producing gas wells
Average production net to Paramount in 2002: 4.8 MMcf/d

Tattoo 1,298 gross (649 net) acres of land assigned reserves
18,818 gross (13,302 net) acres undeveloped lands
2 gross (1.0 net) producing gas wells
1 gross (0.5 net) non-producing gas wells
Average production net to Paramount in 2002: 2.5 MMcf/d

Clarke Lake 14,773 gross (5,916 net) acres of land assigned reserves
1,496 gross (544 net) acres undeveloped lands
14 gross (5.4 net) producing gas wells
9 gross (3.7 net) non-producing gas wells
Annualized production net to Paramount in 2002: 3.2 MMcf/d

Liard non-op 14,708 gross (439 net) acres of land assigned reserves
There are no Company interests in undeveloped lands
2 gross (0.1 net) producing gas wells
1 gross (0.1 net) non-producing gas wells
Average production net to Paramount in 2002: 1.8 MMcf/d

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Southern Alberta/Southeast Saskatchewan/Montana/North Dakota

This is a new core production area for the Company. These properties were part of the Summit acquisition that closed June 28, 2002.

North of the border, the Company produces gas from the Cretaceous Belly River Viking, Glauconitic and Ostracod zones, and the Mississippian Banff limestones. Oil is produced from the Jurassic Sawtooth sandstone in Alberta, and the Midale beds in Saskatchewan.

Oil is produced from the Middle Jurassic Shaunavon formation in Montana as well as the the Mississippian Bakken and the Ordovician Red River. Oil production in North Dakota produces out of the Bakken and the Mission Canyon formation of Mississippian age.

All of the production volumes have been annualized in the following major properties summary.

Chain/ Craigmyle/ Delia	49,127 gross (32,212 net) acres of land assigned reserves 26,960 gross (23,831 net) acres undeveloped lands 62 gross (39.6 net) producing gas wells 22 gross (14.9 net) non-producing gas wells 10 gross (5.4 net) producing oil wells 6 gross (1.4 net) non-producing oil wells Average production net to Paramount in 2002: 1.8 MMcf/d
Retlaw	6,720 gross (4,608 net) acres of land assigned reserves 480 gross (480 net) acres undeveloped lands 4 gross (4.0 net) producing gas wells 7 gross (6.0 net) non-producing gas wells 1 gross (0.4 net) producing oil wells 1 gross (1.0 net) non-producing oil wells Average production net to Paramount in 2002: 1.3 MMcf/d
Sylvan Lake	2,240 gross (1,553 net) acres of land assigned reserves 2,560 gross (2,560 net) acres undeveloped lands 6 gross (4.9 net) producing gas wells 1 gross (1.0 net) non-producing gas wells 1 gross (0.8 net) producing oil wells 2 gross (1.5 net) non-producing oil wells Average production net to Paramount in 2002: 1.0 MMcf/d
Beaver Creek, North Dakota	3,596 gross (2,452 net) acres of land assigned reserves 2,655 gross (1,922 net) acres undeveloped lands 21 gross (8.2 net) producing oil wells 5 gross (1.8 net) non-producing oil wells Average production net to Paramount in 2002: 97 Bbl/d

Annual Information Form

Enchant, Alberta 3,360 gross (2,122 net) acres of land assigned reserves
 1,960 gross (1,654 net) acres undeveloped lands
 1 gross (1.0 net) producing gas wells
 2 gross (1.0 net) non-producing gas wells
 24 gross (20.5 net) producing oil wells
 4 gross (3.9 net) non-producing oil wells
 Average production net to Paramount in 2002: 187 Bbl/d

Knutson, North Dakota 1,473 gross (1,426 net) acres of land assigned reserves
 4,668 gross (3,722 net) acres undeveloped lands
 13 gross (12.7 net) producing oil wells
 2 gross (1.9 net) non-producing oil wells
 Average production net to Paramount in 2002: 196 Bbl/d

Rabbit Hills, Montana 3,608 gross (2,937 net) acres of land assigned reserves
 14,218 gross (13,014 net) acres undeveloped lands
 23 gross (1.8 net) producing gas wells
 8 gross (0.7 net) non-producing gas wells
 18 gross (17.1 net) producing oil wells
 3 gross (2.5 net) non-producing oil wells
 Average production net to Paramount in 2002: 129 Bbl/d

Saskatchewan 11,684 gross (5,676 net) acres of land assigned reserves
 20,760 gross (14,560 net) acres undeveloped lands
 1 gross (0.3 net) non-producing gas wells
 133 gross (66.0 net) producing oil wells
 34 gross (15.7 net) non-producing oil wells
 Average production net to Paramount in 2002: 534 Bbl/d

SELECTED CONSOLIDATED FINANCIAL AND OPERATING INFORMATION

a) Annual Financial Information

(\$ thousands except per share amounts) ⁽¹⁾

Year Ended December 31	2002	2001	2000	1999	1998
Revenues	\$ 473,942	\$ 528,373	\$ 391,470	\$ 211,658	\$ 165,527
Expenses					
Royalties, net of ARTC	74,444	99,706	80,541	37,567	20,874
Operating	86,067	61,045	47,974	39,030	33,005
Interest	23,943	19,291	22,313	15,042	12,745
General and administrative*	15,870	12,346	9,660	8,566	4,452
Lease rentals	4,552	4,319	5,231	4,056	4,185
Current income taxes and other	9,150	27,729	2,305	1,567	2,109
Cash flow from operations	\$ 259,916	\$ 303,937	\$ 223,446	\$ 105,830	\$ 88,157
Per share – basic	\$ 4.37	\$ 5.11	\$ 3.76	\$ 1.84	\$ 1.62
Per share – diluted	\$ 4.36	\$ 5.11	\$ 3.76	\$ 1.84	\$ 1.62
Depreciation and depletion	\$ 169,433	\$ 105,433	\$ 50,563	\$ 47,013	\$ 46,554
Dry hole costs	\$ 120,058	\$ 8,944	\$ 7,019	\$ 10,399	\$ 11,667
Net earnings	\$ 10,307	\$ 118,902	\$ 86,062	\$ 28,683	\$ 18,210

*net of non-cash general and administrative expenses.

Annual Information Form

a) Annual Financial Information (continued)

	Year Ended December 31				
	2002	2001	2000	1999	1998
Per share – basic	\$ 0.17	\$ 2.00	\$ 1.45	\$ 0.50	\$ 0.34
Per share – diluted	\$ 0.16	\$ 2.00	\$ 1.45	\$ 0.50	\$ 0.34
Balance Sheet Information					
Capital expenditures (gross)	\$ 521,264	\$ 261,184	\$ 249,048	\$ 171,079	\$ 215,982
Gross property/equipment sales	\$ 4,995	\$ 11,763	\$ 34,205	\$ 1,894	\$ 19,042
Working capital (deficiency)	\$ (15,973)	\$ 25,902	\$ 22,640	\$ 16,437	\$ (2,346)
Total assets	\$ 1,536,384	\$ 1,176,323	\$ 1,047,829	\$ 740,454	\$ 624,195
Long-term operating bank debt	\$ 539,270	\$ 316,600	\$ 315,000	\$ 268,819	\$ 226,439
Shareholders' equity	\$ 546,105	\$ 535,384	\$ 418,254	\$ 328,992	\$ 262,932
Dividends paid	–	–	–	\$ 2,973	\$ 2,848
Per share	–	–	–	\$ 0.05	\$ 0.05
Share information					
Average number of common shares outstanding (thousands)	59,458	59,454	59,454	57,529	54,348
Market price					
High	\$ 17.60	\$ 18.75	\$ 20.00	\$ 26.00	\$ 17.00
Low	\$ 13.00	\$ 12.00	\$ 10.50	\$ 12.00	\$ 11.00

b) Annual Operating Information

Year Ended December 31	2002	2001	2000	1999	1998
Reserves (proved and probable)					
Natural gas (Bcf)	619	564	657	750	788
Crude oil and liquids (MBbl)	22,846	7,967	5,980	8,880	11,630
Land holdings (thousands of acres)					
Gross	7,675	6,575	6,216	4,373	4,030
Net	5,077	4,984	4,648	2,834	2,433
Production					
Natural gas (MMcf/d)	241.4	225.0	220.0	220.0	203.5
Average natural gas price (\$/Mcf)	\$ 4.08	\$ 6.12	\$ 4.59	\$ 2.43	\$ 2.02
Crude oil and liquids (Bbl/d)	5,663	2,165	1,571	1,854	1,988
Average crude oil price (\$/Bbl)	\$ 34.64	\$ 35.48	\$ 37.80	\$ 24.27	\$ 19.22
Drilling activity (gross)					
Gas wells	114	167	126	92	111
Oil wells	9	12	11	9	24
Standing/service	1	1	2	3	8
Dry and abandoned	11	16	24	10	29
Total	135	196	163	114	172
Success rate (%)	92	92	85	91	83
Number of employees					
Office	152	108	89	70	63
Field	128	80	68	53	65
Total	280	188	157	123	128

(1) All per share amounts are calculated using average number of shares outstanding, except dividends paid per share which are based upon actual shares outstanding at time of dividend declaration.

Annual Information Form

c) Quarterly Financial Information

The following information is presented with respect to each of the last eight fiscal quarters.

(\$ thousands except per share amounts)

	2002				2001			
	Dec. 31	Sept. 30	June 30	March 31	Dec. 31	Sept. 30	June 30	March 31
Net revenue	\$ 110,180	\$ 95,780	\$ 110,206	\$ 83,332	\$ 75,232	\$ 92,756	\$ 114,358	\$ 146,321
Earnings (loss)	\$ (41,399)	\$ 6,180	\$ 26,614	\$ 18,912	\$ (10,433)	\$ 33,249	\$ 38,889	\$ 57,197
Per share – basic	\$ (0.70)	\$ 0.10	\$ 0.45	\$ 0.32	\$ (0.18)	\$ 0.56	\$ 0.66	\$ 0.96
Per share – diluted	\$ (0.70)	\$ 0.10	\$ 0.44	\$ 0.32	\$ (0.18)	\$ 0.56	\$ 0.66	\$ 0.96
Cash flow	\$ 62,102	\$ 58,661	\$ 80,956	\$ 58,197	\$ 47,732	\$ 66,155	\$ 70,654	\$ 119,396
Per share – basic	\$ 1.04	\$ 0.99	\$ 1.36	\$ 0.98	\$ 0.80	\$ 1.11	\$ 1.19	\$ 2.01
Per share – diluted	\$ 1.04	\$ 0.99	\$ 1.36	\$ 0.98	\$ 0.80	\$ 1.11	\$ 1.19	\$ 2.01

Paramount has paid a cash dividend in two of the last five fiscal years. Future payments will be dependent upon the financial requirements of the Company to reinvest earnings, the financial condition of the Company and other factors which the Board of Directors of the Company may consider appropriate. The following table summarizes the Company's dividend payment record.

	2002	2001	2000	1999	1998
Per share	–	–	–	\$ 0.050	\$ 0.050
Dividends paid (\$ thousands)	–	–	–	\$ 2,973	\$ 2,848

MANAGEMENT DISCUSSION AND ANALYSIS (MD&A – SEE PAGES 26 TO 39)

See the Company's Management's Discussion and Analysis relating to the audited financial statements for the fiscal years ended December 31, 2002 and 2001, which form part of this Annual Report.

MARKET FOR SECURITIES

The Common shares of Paramount Resources Ltd. are listed on The Toronto Stock Exchange under the trading symbol 'POU'.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration, principal holders of Paramount Resources Ltd. securities, options to purchase securities, and interests of insiders in material transactions, where applicable, is contained in Paramount's Management Information and Proxy Circular dated March 19, 2003. Additional financial information is contained in the Company's comparative financial statements for the year ended December 31, 2002.

For additional copies of this Annual Report and the materials listed in the preceding paragraphs, please contact:

J.H.T. (Jim) Riddell

President and Chief Operating Officer

Shareholder Information

OFFICERS

C.H. Riddell

Chief Executive Officer
and Chairman of the Board

J.H.T. Riddell

President
and Chief Operating Officer

D.J. Broshko

Chief Financial Officer

C.E. Morin

Corporate Secretary

W.B. Cawston

Corporate Operating Officer

L.M. Doyle

Corporate Operating Officer

C.G. Folden

Corporate Operating Officer

H.S. Klaassen

Corporate Operating Officer

J.B. Williams

Corporate Operating Officer

L.A. Friesen

Assistant Corporate Secretary

DIRECTORS

C.H. Riddell ⁽³⁾

Chief Executive Officer
and Chairman of the Board
Paramount Resources Ltd.
Calgary, Alberta

J.H.T. Riddell

President
Paramount Resources Ltd.
Calgary, Alberta

J.C. Gorman ⁽¹⁾

Business Executive
Calgary, Alberta

D. Jungé, C.F.A.

Chairman and
Chief Executive Officer
Pitcairn Trust Company
Jenkintown, Pennsylvania

D.M. Knott

General Partner
Knott Partners, L.P.
Syosset, New York

W.B. MacInnes, Q.C. ⁽¹⁾⁽²⁾

Barrister & Solicitor
Counsel, Gowling Lafleur
Henderson LLP
Calgary, Alberta

V.S.A. Riddell

Business Executive
Calgary, Alberta

S.L. Riddell Rose

President and
Chief Operating Officer
Paramount Energy Trust
Calgary, Alberta

J.B. Roy ⁽¹⁾⁽²⁾⁽³⁾

Vice President and Director
Investment Banking
Jennings Capital Inc.
Calgary, Alberta

A.S. Thomson

President
Touche, Thomson & Yeoman
Investment Consultants Ltd.
Calgary, Alberta

B.M. Wylie ⁽²⁾⁽³⁾

Business Executive
Calgary, Alberta

(1) Member Of Audit Committee

(2) Member Of Environmental Committee

(3) Member Of Compensation Committee

CONSULTING ENGINEERS

McDaniel & Associates
Consultants Ltd.
Calgary, Alberta

Sproule Associates Limited
Calgary, Alberta

Sproule Associates Inc.
Denver, Colorado

AUDITORS

Ernst & Young LLP
Calgary, Alberta

BANKERS

Bank Of Montreal
Main Branch
Calgary, Alberta

REGISTRAR AND TRANSFER AGENT

Computershare Investor
Services Canada
Calgary, Alberta
Toronto, Ontario

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
("POU")

HEAD OFFICE

4700 Bankers Hall West
888 Third Street S.W.
Calgary, Alberta, Canada
T2P 5C5

Telephone: (403) 290-3600
Facsimile: (403) 262-7994
www.paramountres.com

ANNUAL MEETING

Shareholders are cordially invited
to attend the Annual Meeting to
be held June 26, 2003 at 3:30 pm
Calgary Petroleum Club
Devonian Room
319 Fifth Avenue S.W.
Calgary, Alberta

This report contains forward-looking information with respect to Paramount Resources Ltd. This forward-looking information is based on certain assumptions that involve a number of risks and uncertainties and are not guarantees of future performance.

MAJOR PRODUCING PROPERTIES

The following table summarizes average production volumes from Paramount's major producing properties for each of the last five fiscal years.

Property	2002	2001	2000	1999	1998
Sturgeon Lake	294	281	266	176	176
Northwest Alberta	281	271	256	176	176
Sturgeon Lake	281	271	256	176	176
Sturgeon Lake	281	271	256	176	176
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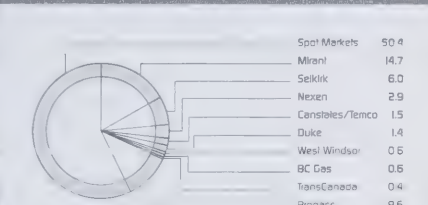
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Sturgeon Lake	281	271	256	176	176
Sturgeon Lake	281	271	256	176	176
Sturgeon Lake	281	271	256	176	176

GAS SALES & MARKETS

Market	2002	2001
Alberta	14.7	17.4
British Columbia	4.6	8.4
TransCanada	4.6	2.7
Constance/Tenno	1.0	1.0
Saskatchewan	6.0	4.5
Nexen	2.9	-
West Windsor	0.6	-
BC Gas	1.4	-
Duke	1.4	-
California Spot	13.8	14.6
Chicago	3.2	-
Eastern Canada	2.7	-
Alberta/Waddington Spot	30.7	32.9
Total Sales	88.1	82.1
Aggregators	30%	37%
Direct sales	13%	6%
Spot Market	57%	57%

2002 NATURAL GAS SALES DISTRIBUTION (Bcf)



Market	2002	2001
Alberta	14.7	17.4
British Columbia	4.6	8.4
TransCanada	4.6	2.7
Constance/Tenno	1.0	1.0
Saskatchewan	6.0	4.5
Nexen	2.9	-
West Windsor	0.6	-
BC Gas	1.4	-
Duke	1.4	-
California Spot	13.8	14.6
Chicago	3.2	-
Eastern Canada	2.7	-
Alberta/Waddington Spot	30.7	32.9
Total	88.1	82.1

CAPITAL EXPENDITURES

Property	2002	2001
Sturgeon Lake	294	281
Northwest Alberta	281	271
Sturgeon Lake	281	271
Sturgeon Lake	281	271
Sturgeon Lake	281	271
Sturgeon Lake	281	271
Sturgeon Lake	281	271
Sturgeon Lake	281	271
Sturgeon Lake	281	271
Sturgeon Lake	281	271
Sturgeon Lake	281	271

*Six-month production volumes from this core area have been averaged over 12 months annualized.

PROFIT SUMMARY

Property	2002	2001	2000	1999	1998
Sturgeon Lake	294	281	266	176	176
Northwest Alberta	281	271	256	176	176
Sturgeon Lake	281	271	256	176	176
Sturgeon Lake	281	271	256	176	176
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Sturgeon Lake	281	271	256	176	176

BALANCE SHEET INFORMATION

As at December 31	2002	2001	Change
Assets			
Current assets	\$ 123.4	\$ 119.8	4
Property & equipment, net	1412.0	1,058.8	353
Liabilities and Equity			
Current liabilities	\$ 140.4	\$ 92.1	52
Bank loans	539.3	316.6	70
Future site restoration	23.0	9.0	166
Deferred revenue	7.8	1.4	457
Future income taxes	279.8	221.9	26
Shareholders' equity	546.1	537.2	2
Net appraised asset value	\$ 1,536.4	\$ 1,178.1	30

CAPITAL STRUCTURE

The following table outlines Paramount's capital structure since 1998.

Property	2002	2001	2000	1999	1998
Sturgeon Lake	294	281	266	176	176
Northwest Alberta	281	271	256	176	176
Sturgeon Lake	281	271	256	176	176
Sturgeon Lake	281	271	256	176	176
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Sturgeon Lake	281	271	256	176	176

NET DEBT

At December 31	2002	2001
Current assets	\$ 124,423	\$ 117,986
Less current liabilities	140,396	92,084
Working capital (deficiency)	(15,973)	25,902
Bank loans	539,270	316,600
Net debt	\$ 555,243	\$ 290,698

ESTIMATED FUTURE PRE-TAX CASH FLOW

Property	2002	2001	2000	1999	1998
Sturgeon Lake	294	281	266	176	176
Northwest Alberta	281	271	256	176	176
Sturgeon Lake	281	271	256	176	176
Sturgeon Lake	281	271	256	176	176
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Sturgeon Lake	281	271	256	176	176

The discounted net present values of the estimated pre-tax cash flow expected during the economic life of all reserves are based on estimates using escalating price assumptions at rates of 10%, 15% and 20% per annum compounded annually. They are calculated prior to the consideration of income taxes but include ARTC, and are not to be construed as representing the fair market value of properties. The fair market value of the properties and such net present values will depend upon the subjective considerations inherent to each property.

NET APPRAISED ASSET VALUE PER COMMON SHARE

As at December 31, 2002	2002	2001	2000	1999	1998
Discount rate	10%	12%	15%	-	-
Present value of reserves	\$ 1,123.7	\$ 1,057.2	\$ 973.3	-	-
Market value of short term investments	14.2	14.2	14.2	-	-
Fair market value of undeveloped land	117.3	117.3	117.3	-	-
Other (net of associated debt)	12.4	12.4	12.4	-	-
Subtotal	1,267.6	1,209.2	1,125.3	-	-
Working capital deficiency	(30.1)	(30.1)	(30.1)	-	-
Debt	(531.2)	(531.2)	(531.2)	-	-
Net appraised asset value	\$ 706.3	\$ 639.8	\$ 555.9	-	-
Net appraised asset value per common share	\$ 11.88	\$ 10.75	\$ 9.34	-	-

(1) Proved plus half probable, includes benefit of ARTC with no allowance for income tax.

(2) Based on oil and gas reserves as at December 31, 2002.

KEY RATIOS

Property	2002	2001	2000	1999	1998
Sturgeon Lake	294	281	266	176	176
Northwest Alberta	281	271	256	176	176
Sturgeon Lake	281	271	256	176	176
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Sturgeon Lake	281	271	256	176	176

NET DEBT TO CASH FLOW RATIO

Property	2002	2001	2000	1999	1998
Sturgeon Lake	294	281	266	176	176
Northwest Alberta	281	271	256	176	176
Sturgeon Lake	281	271	256	176	176
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DEBT TO EQUITY RATIO

Property	2002	2001	2000	1999	1998
Sturgeon Lake	294	281	266	176	176
Northwest Alberta	281	271	256	176	176
Sturgeon Lake	281	271	256	176	176
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Sturgeon Lake	281	271	256	176	176
Sturgeon Lake	281	271	256	176	176

(1) Trend with base year 1998 with a nominal value of 100.

CASH FLOW RECONCILIATION

	December 31				
Property	2002	2001	2000	1999	1998
Gross revenue	474.9	528.4	891.5	211.7	166.8
Net royalties	74.1	99.7	80.6	17.6	20.0
Net revenue	399.5	428.7	310.9	174.1	144.6
Expenses					
Operating	86.1	61.1	48.0	39.0	35.0
Cash G&A	15.9	12.4	9.7	8.6	4.5
Lease rentals	4.6	4.3	5.2	4.1	4.2
Interest on bank loan	23.9	19.3	22.3	15.0	12.7
Current income taxes and other	9.1	27.7	2.3	1.6	2.1
Cash flow	259.9	303.9	223.4	105.8	88.1
Cash flow as a % of net revenue	65	71	72	61	61

(1) Includes gain on sale of investments

OIL & GAS SALES AND GROSS PROFIT

This illustrates oil and gas sales since 1996 and converts the oil sales into gas equivalent (Mcfe) on an industry standard basis of one barrel of crude oil/liquids equals 10 Mcfe of natural gas.

Fiscal Year	Oil & Gas revenue (\$ 000s)		Gas production MMcf/Trend		Average price Gas \$ / Mcfe		Gas equivalent production MMcf/Trend	
	\$ 000s	Trend	MMcf	Trend	\$ / Mcfe	Trend	MMcf	Trend
1998	165,327	100	74,278	100	2.23	19.22	81,578	100
1999	211,638	128	80,300	108	2.43	24.27	87,067	107
2000	391,470	236	80,520	108	4.89	37.50	80,270	106
2001	525,896	318	82,125	111	6.32	35.45	90,627	110
2002	441,001	260	88,111	119	4.08	34.64	108,781	133

1. Trend with base year 1998 with nominal value of 100.

OPERATING CASH NETBACKS

Fiscal Year	Revenue net ARTC (\$ 000s / \$/Mcfe)		Operating cost (\$ 000s / \$/Mcfe)		Operating cash netback (\$ 000s / \$/Mcfe)		Operating cash netback (\$ 000s / \$/Mcfe)	
	\$ 000s	\$/Mcfe	\$ 000s	\$/Mcfe	\$ 000s	\$/Mcfe	\$ 000s	\$/Mcfe
1998	20,874	0.26	100	33,005	0.40	100	110,077	1.35
1999	37,567	0.43	165	39,030	0.45	113	133,061	1.55
2000	90,541	0.88	358	17,974	0.96	140	262,955	1.95
2001	99,706	1.11	427	61,045	0.68	170	364,935	4.05
2002	74,444	0.86	292	69,067	0.79	199	272,901	2.51

(1) Trend with base year 1998, with nominal value of 100.

(2) Operating Cash Netback = Oil & Gas and Other Revenue - Royalty - Operating Cost

REVENUE/EXPENSES/CASH FLOW NETBACK/NET EARNINGS

The table calculates revenue, expenses and net earnings converted into dollars per thousand cubic feet gas equivalents (1 Barrel equals 10 Mcfe).

	2002	2001	2000	1999	1998
Annual Production (MMcf)	108,781	90,027	86,270	87,067	81,578
Revenue	\$ 3.98	\$ 5.84	\$ 4.54	\$ 2.43	\$ 2.03
Net royalties	0.08	1.11	0.05	0.43	0.26
Operating costs	0.79	0.68	0.56	0.45	0.40
Cash netback	2.51	4.05	3.05	1.55	1.37
General and administrative	0.15	0.14	0.11	0.10	0.05
Interest on bank loans	0.22	0.21	0.35	0.37	0.16
Lease rentals and other taxes	0.12	0.06	0.09	0.07	0.08
Cash flow netback	2.02	3.34	2.50	1.21	1.08
Depletion, depreciation and site restoration	1.39	1.20	0.59	0.34	0.56
Surmount compensation	(0.34)	0.02	(0.01)	(0.02)	(0.04)
Depletion, depreciation and site restoration	1.19	0.09	0.09	0.12	0.15
Write-down of petroleum and natural gas properties	0.29	0.12	0.08	0.03	0.06
Geological and geophysical	0.09	0.12	0.08	0.03	0.06
Current and capital taxes	0.38	0.03	0.03	0.03	0.06
Earnings (loss) before income taxes	(0.33)	1.93	1.84	0.54	0.33
Future income taxes (recovery)	(0.43)	0.82	0.84	0.21	0.11
Net earnings	\$ 0.10	\$ 1.31	\$ 1.00	\$ 0.33	\$ 0.22
Net earnings trend ⁽¹⁾	45	595	454	150	100

(1) Trend with base year 1996, with nominal value of 100.



Paramount
resources ltd.

ANNUAL REPORT 2002 ANALYST SUPPLEMENT

This handbook has been prepared by Paramount Resources Ltd. to address the special information needs of the investment community and the sophisticated investor. The handbook provides detailed performance data and key ratios. For additional information please contact:

J.H.T. (Jim) Riddell, President and Chief Operating Officer

CORPORATE PROFILE

Paramount Resources Ltd. is a Canadian energy company with its revenue derived primarily from natural gas sales. The Company explores for, develops, produces and markets natural gas, crude oil and natural gas liquids. Paramount has an aggressive, focused exploration and development strategy, concentrated on acquiring land and establishing reserves throughout the Western Canadian Sedimentary Basin.

- 24 years old
- 280 employees (152 head office, 128 field)
- Listed on the Toronto Stock Exchange: symbol "POU"
- Part of the S&P/TSX Composite Index
- 59,459 million shares outstanding at December 31, 2002
- Market Capitalization: \$892 million (December 31, 2002)

Year	Cash flow	Basic per share	Earnings	Basic per share
2000	\$ 223.4 million	\$ 3.76	\$ 86.1 million	\$ 1.45
2001	\$ 303.9 million	\$ 5.11	\$ 118.9 million	\$ 2.00
2002	\$ 259.9 million	\$ 4.37	\$ 10.3 million	\$ 0.17

Average number of common shares outstanding for 2002 was 59,458,000.

UNIQUE FACTS

- Over 80% of revenue derived from natural gas sales
- "Successful Efforts" accounting policy results in conservative net earnings
- High management ownership (54%)
- Successful full cycle exploration and development creates shareholder value
- Proven performance record through 24 years of commodity price cycles
- Exposure to high impact exploration plays in Colville Lake, the Liard Basin and Cameron Hills in the N.W.T.

Paramount Resources Ltd.
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888 Third Street S.W.
Calgary, Alberta
Canada T2P 5C5
TEL 403 280 3600
FAX 403 282 2984
WEB www.paramountres.com

CONSOLIDATED EARNINGS & CASH FLOW DATA

Year ended December 31			
	2002	2001	Change
Revenue	\$ 399.5	\$ 428.7	(7)
Natural gas	72.8	28.1	236
Crude oil & liquids	(74.4)	(99.7)	25
Royalties, net of ARTC	60.8	8.0	1,960
Gain on sale of investments	2.1	(0.3)	800
Other income (loss)	399.5	428.7	(7)
Expenses	86.1	61.1	40
Operating	86.1	61.1	40
Surmount compensation	23.9	19.3	23
Interest	16.2	12.4	31
General and administrative	120.1	9.0	1,234
Dry hole	9.3	10.6	(12)
Geological and geophysical	4.6	4.3	7
Lease rentals	3.4	2.4	42
Site restoration	169.4	105.4	61
Depletion and depreciation	31.3	-	-
Write-down of petroleum and natural gas properties	9.1	27.7	(67)
Other income/expense	(46.9)	56.1	(184)
Current and capital taxes	\$ 10.3	\$ 118.9	(91)
Future income taxes	\$ 0.17	\$ 2.00	(92)

CASH FLOW RECONCILIATION

Net revenue	\$ 399.5	\$ 428.7	(7)
Expenses	86.1	61.1	40
Operating	23.9	19.3	23
Interest	16.2	12.4	31
Cash G & A	4.6	4.3	7
Lease rentals	3.4	2.4	42
Site restoration	9.1	27.7	(67)
Current and capital taxes	\$ 259.9	\$ 893.6	15
Cash flow	\$ 4.37	\$ 5.11	(15)
Cash flow per common share - basic	65%	71%	(8)

COMPANY FORECAST 2003

Production / Pricing	160 @ \$ 28.00
Gas (MMcf/d) - \$/Mcfe	7,000 @ \$ 28.00
Oil/liquids (SWT) (Bbl/d)	\$ 200
Cash flow (\$MM)	\$ 200
Cash flow per share	\$ 2.00
Capital budget (\$MM)	\$ 150

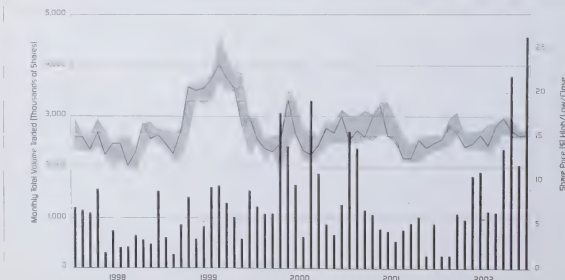
COMMON SHARE DATA

Shares of Paramount Resources Ltd. trade on The Toronto Stock Exchange under the symbol "POU" - Oil and Gas Producers-S&P Index and is part of the S&P/TSX Composite Index.

	2002	2001
At December 31	59,459	59,434
Outstanding shares	59,459	59,434
Public float - shares	47,480	47,482
Public float - % of total shares	48%	48%
Trading volumes	21,025	11,019
Trading volumes - incl public float	75%	47%
Trading value \$MM	\$ 319,369	\$ 195,330
High	\$ 17.60	\$ 18.75
Low	\$ 13.00	\$ 12.00
Close	\$ 15.00	\$ 14.10
Weighted average trading price	\$ 15.19	\$ 15.00
Market capitalization at year end (\$ million)	\$ 891.9	\$ 838.3

(1) Public float is all outstanding shares less shares owned/controlled by officers/directors

FIVE YEAR PRICE AND TRADING VOLUME



DIKRETT & ASSOCIATES	J.C. (John) Riddell Director / Chairman	J.C. (John) Riddell Director
CH. (Clay) Riddell Director / Chairman	D. (Dale) Duggs, C.F.A. Director	D. (Dale) Duggs, C.F.A. Director
J.H.T. (Jim) Riddell Director / President and Chief Operating Officer	D.M. (David) MacInnes Director	D.M. (David) MacInnes Director
D.J. (David) Brinko Chief Financial Officer	V.S.A. (Viv) Riddell Director	V.S.A. (Viv) Riddell Director
C.E. (Chuck) Moran Corporate Secretary	S.L. (Steve) Riddell Director	S.L. (Steve) Riddell Director
L.A. (Laurie) Friesen Assistant Corporate Secretary	W.B. (Bruce) Duggs Corporate Operating Officer	W.B. (Bruce) Duggs Corporate Operating Officer
J.M. (John) Duggs Corporate Operating Officer	A.S. (Arlene) Friesen Director	A.S. (Arlene) Friesen Director
C.G. (Craig) Friesen Corporate Operating Officer	E.M. (Eileen) Williams Director	E.M. (Eileen) Williams Director

COMPANY FORECAST 2003

Production / Pricing

Gas (MMcf/d) (\$/Mcf)	160 @ \$	5.80
Oil/liquids (\$WTI) (Bbl/d)	7,000 @ \$	28.00
Cash flow (\$MM)	\$	200
Cash flow per share	\$	3.30
Capital budget (\$MM)	\$	150

COMMON SHARE DATA

Shares of Paramount Resources Ltd. trade on The Toronto Stock Exchange under the symbol "POU" (Oil and Gas Producers Sub Index) and is part of the S&P/TSX Composite Index.

At December 31	2002	2001
Outstanding shares (000s)	59,459	59,454
Public float ⁽¹⁾ – shares (000s)	27,480	27,432
– % of total shares	46%	46%
Trading volume (000s)	21,027	13,019
Trading volume as % of public float	77%	47%
Trading value (000s)	\$ 319,369	\$ 195,330
Trading range		
High	\$ 17.60	\$ 18.75
Low	\$ 13.00	\$ 12.00
Close	\$ 15.00	\$ 14.10
Weighted average trading price	\$ 15.19	\$ 15.00
Market capitalization at year end (\$ millions)	\$ 891.9	\$ 838.3

(1) Public float is all outstanding shares less shares owned/controlled by officers/directors

DIRECTORS AND OFFICERS

C.H. (Clay) Riddell
Director, Chairman
and Chief Executive Officer

J.H.T. (Jim) Riddell
Director, President
and Chief Operating Officer

D.J. (David) Broshko
Chief Financial Officer

C.E. (Chuck) Morin
Corporate Secretary

L.A. (Laurel) Friesen
Assistant Corporate Secretary

W.B. (Bruce) Cawston
Corporate Operating Officer

L.M. (Lloyd) Doyle
Corporate Operating Officer

C.G. (Cal) Folden
Corporate Operating Officer

H.S. (Hugh) Klaassen
Corporate Operating Officer

J.B. (John) Williams
Corporate Operating Officer

J.C. (John) Gorman
Director

D. (Dirk) Jungé, C.F.A.
Director

D.M. (David) Knott
Director

W.B. (Wally) MacInnes, Q.C.
Director

V.S.A. (Vi) Riddell
Director

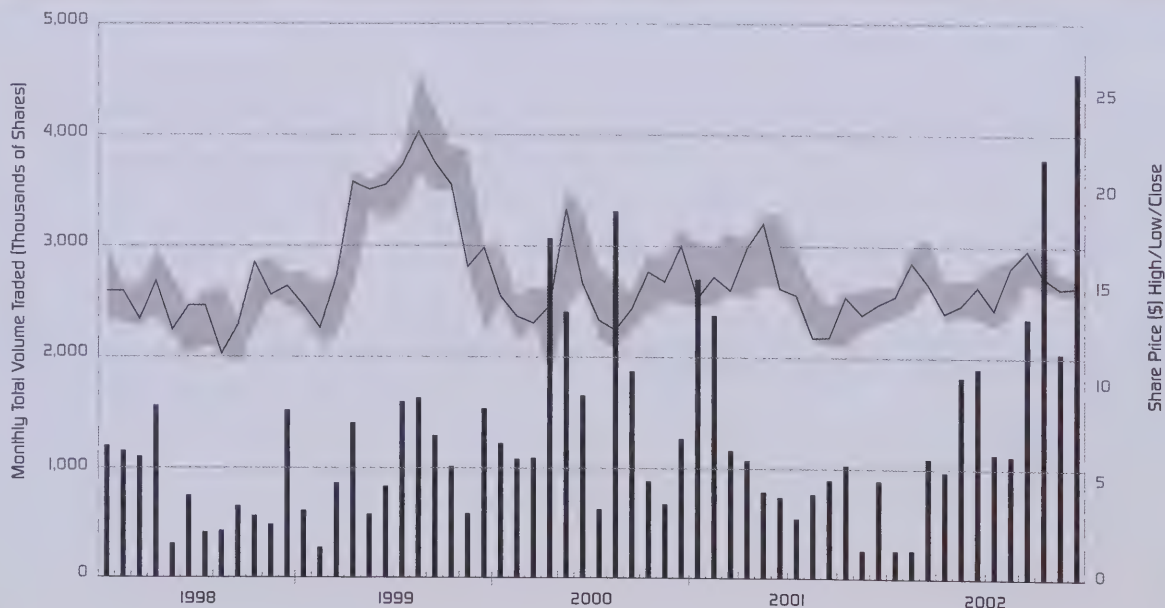
S.L. (Sue) Riddell Rose
Director

J.B. (John) Roy
Director

A.S. (Alistair) Thomson
Director

B.M. (Bernie) Wylie
Director

FIVE-YEAR SHARE PRICE AND TRADING VOLUME



MANAGEMENT

Clayton H. Riddell
Chairman of the Board and Chief Executive Officer

Susan L. Riddell Rose
President and Chief Operating Officer

Gary C. Jackson
Vice President, Land, Legal and Acquisitions

Kevin J. Marjoram
Vice President, Operations

Cameron R. Sebastian
Vice President, Finance and Chief Financial Officer

Myra Jones
Corporate Secretary

DIRECTORS

Clayton H. Riddell ⁽³⁾

Chief Executive Officer and Chairman of the Board
Paramount Energy Operating Corp.

Susan L. Riddell Rose ⁽⁸⁾

President and Chief Operating Officer
Paramount Energy Operating Corp.

Karen A. Genoway ⁽³⁾⁽⁴⁾

Vice President, Land
Onyx Energy Inc.

Donald J. Nelson ⁽¹⁾⁽²⁾⁽³⁾

Business Executive
John W. Peltier ⁽¹⁾⁽²⁾⁽⁴⁾

President,
Ipperwash Resources Ltd.

Howard R. Ward ⁽¹⁾⁽⁴⁾

Partner,
International Energy Council

⁽¹⁾ Member of Audit Committee

⁽²⁾ Member of Environmental Committee

⁽³⁾ Member of Compensation Committee

⁽⁴⁾ Member of Corporate Governance Committee

AUDITORS

KPMG LLP

BANKERS

Bank of Montreal
Canadian Imperial Bank of Commerce
Bank of Nova Scotia

**RESERVE EVALUATION
CONSULTANTS**

McDaniel & Associates Consultants Ltd.

**TRUSTEE REGISTRAR
AND TRANSFER AGENT**

Computershare Trust Company of Canada

STOCK EXCHANGE LISTING

Toronto Stock Exchange "PMTUN"

HEAD OFFICE

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Website: www.paramountenergy.com

ANNUAL MEETING

Shareholders are cordially invited to attend the Annual
Meeting to be held June 18, 2003 at 3:00 p.m.

Calgary Petroleum Club
McMurray Room

319 Fifth Avenue S.W.
Calgary, Alberta

*This report contains forward-looking information with
respect to Paramount Energy Trust ("PET"). This forward-
looking information is based on certain assumptions
that involve a number of risks and uncertainties and
are not guarantees of future performance. Actual results
could differ materially as a result of changes in PET's
plans, changes in commodity prices, general economic,
market and business conditions as well as production,
development and operating performance, regulations,
and other risks associated with oil and gas operations.*

Review of Operations (continued)

NORTHEAST ALBERTA EAST SIDE

Natural gas in the East Side core area is trapped in multiple Cretaceous clastic reservoirs in the McMurray, Wabiskaw, Clearwater, Grand Rapids and Colony Formations. Drilling depths are typically less than 450 meters and initial reservoir pressures average 600 to 2,200 kPa (85 to 320 psi). Initial well productivity ranges from 200 to 2,000 Mcf/d. Pools are found using detailed mapping and extensive 2D seismic bright spot technology. With the exception of the Cold Lake, Thornbury and Wintefield assets, which are produced through third party facilities for a custom processing fee, POT produced the majority of its 54.9 MMcfd of average natural gas production in 2002 from five company-operated gas plants.

East Side Property	Reserves ⁽¹⁾	Proven & Probable (Bcf)	Average Production (MMcfd)	Working Interest ⁽²⁾ (%)	Undeveloped Land (acres)	Operating Costs	
						Net	Operating Costs
Bohn Lake	5.9	3.5	2.6	27.6	533	11,430	0.85
Chard/Chard SW	3.5	2.7	2.8	93.8	14,080	30,569	0.85
Clyde	17.0	23.5	13.9	99.0	94.7	27,200	0.85
Corner	8.0	12.7	9.5	91.6	90,911	3,040	0.85
Leismer	1.2	4.7	3.3	100.0	13,760	1,280	0.85
Pony	14.9	4.5	73.5	1,152	22,000	105.5	0.85
Thornbury	11.4	4.6	88.5	22,000	54.9	—	0.85
Wintefield	105.5	54.9	—	215,955	Subtotal		0.85

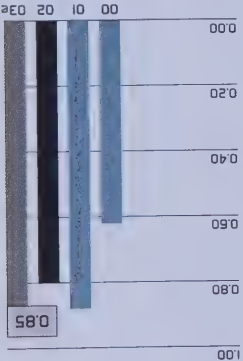
RESERVES

The following table is a comparison of Paramount Operating Trust's natural gas reserves at January 1, 2003 and July 2, 2002, the effective date of POT's acquisition of its northeast Alberta assets, as evaluated by the independent reserve engineering firm McDaniell & Associates Consultants Ltd., utilizing escalating price assumptions. After production of 17.2 Bcf over the six-month period, additions and upward revisions of 20.2 Bcf (12.5%) on proven reserves and 21.4 Bcf (10.7%) on proven and probable reserves were realized. Most of the reserve increase related to upward revisions as virtually no capital was expended during the period. The largest upward production performance at Legend, Corner, North Lige and Quigley, where better than anticipated production occurred as a result of successful field operation optimization programs. The revised reserve estimates lead to an increase in the reserve life index from 6.1 to 6.6 years.

(1) Gross Company Reserves as at Jan 1, 2003.
(2) Refers to the average working interest in producing gas wells.

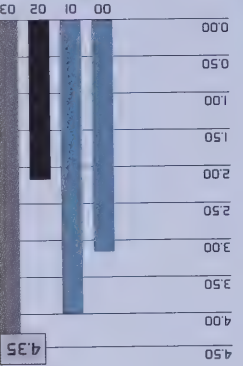
RESULTS

Operating Costs (\$/Mcf)



RESULTS

Operating Netback (\$/Mcf)



Review of Operations

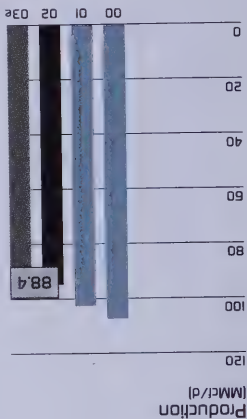
PET's operations are extremely focused, concentrated on the production of shallow natural gas in northeast Alberta. These properties feature well established high working interest production with relatively low operating costs and access to stable markets. These factors combine to deliver high field netbacks. Low cost opportunities for value creation exist throughout the asset base, requiring small capital expenditures to partially offset annual production declines.

The asset base can be divided into two core areas. The West Side includes assets west of Alberta Highway 63 which began with production from Devonian carbonate reservoirs. The East Side, including Cold Lake, is comprised of assets east of Alberta Highway 63 and production is mainly from Cretaceous clastic reservoirs.

NORTHEAST ALBERTA WEST SIDE

The West Side is characterized by high deliverability shallow gas produced from the Devonian McMurray sands. Vertical wells are typically less than 350 meters and initial reservoir pressures average 200 to 1,700 kPa (30 to 250 psi). Initial well productivity ranges from 200 to 5,000 Mcf/d. Leading-edge horizontal drilling technology has become a major exploitation technique in this region, targeting to increase per well deliverability while minimizing reservoir drawdown and reducing the requirements for expensive gathering systems. POT averaged production of 38.9 MMcfd from five gas plants, four of which are company-operated, in 2002.

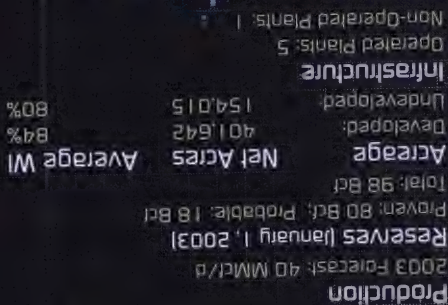
RESULTS



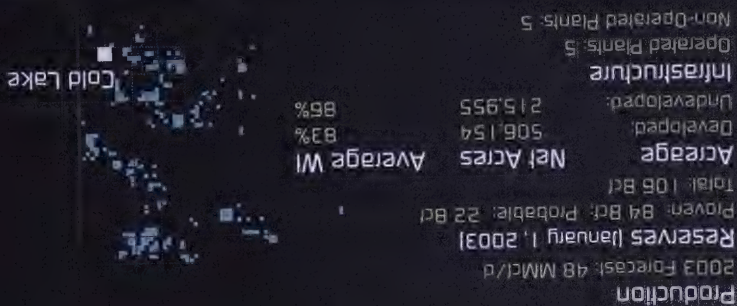
West Side	Property	Reserves ⁽¹⁾	Proven & Probable	Average Production	Working Interest ⁽²⁾	Undeveloped Land	Net
	(Bcf)	(MMcfd)	(%)	(acres)			
Hooley	7.1	0.0	100.0	5,760	70.0	2,880	40,422
Legend	64.1	19.4	82.0	24,960	91.6	1,686	12,163
Legend East	4.3	3.9	2.2	94.9	96.8	19,424	46,720
Liege East	3.9	2.8	94.9	154,015	95.1	50.0	105.0
Liege North	6.6	4.3	4.0	1.7	38.9	—	—
Liege South	6.4	11.3	4.0	1.7	38.9	—	—
Saleski	11.3	1.0	50.0	154,015	95.1	50.0	105.0
Teepee Creek	1.0	1.7	38.9	154,015	95.1	50.0	105.0
Subtotal ⁽³⁾	105.0	38.9	—	—	—	—	—

(1) Gross company reserves as at Jan 1, 2003, March 15, 2003 for Ellis property.
 (2) Refers to the average working interest in producing gas wells.
 (3) Ellis property acquired March 19, 2003.

NORTHEAST ALBERTA (West Side)



NORTHEAST ALBERTA (East Side)



Letter to Unitholders (continued)

requirements and strategic infrastructure ownership. At January 1, 2003, the Trust's established reserves were 184 Bcf, with 97 percent of POT's proved reserves classified as proved producing and 81 percent of the proved plus probable reserves classified as proved. The reserve estimates lead to a calculated reserve life index of 6.6 years on a proven plus probable basis, up from 6.1 years as calculated on the basis of the July 1, 2002 reserve report. Over half of the current production comes from five properties including Legend, Corner, Kettle River and Cold Lake. The Trust operates over 94 percent of its production and has an average 82 percent working interest in the developed lands.

The marketing portfolio of the Trust is relatively simple. Fifty six percent of POT's production is uncontracted and sold at AECO spot prices, with almost all of the remainder dedicated to aggregators. Assuming successful truncation of the Mirant (Pan Alberta) pool as expected, 76 percent of gas will be uncontracted effective Nov 1, 2003. Based on the current NYMEX one year forward price of \$5.67 US/MMBtu, estimated AECO prices will approximate \$6.95 Cdn/GJ. PFT's suite of contracts blended with the 2003 current forward market results in an average 2003 plant gate forecast of \$7.58 Cdn/Mcf. With the current volatility in the natural gas commodity market, these prices will most certainly be out of date by the time this report is distributed, accentuating the necessity for a hedging program to maintain our strategy of providing stable distributions to unitholders. Although we remain very bullish about the fundamentals of the natural gas supply/demand equation, we will seek to add some insurance to distribution levels through a staged hedging program for the remainder of 2003 and forward.

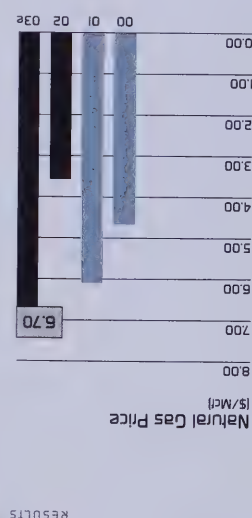
A significant proportion of available cash flow will be distributed to Unitholders this year, as the capital program executed in the first quarter was very small and the vast majority of the assets are winter-access only. In future years, distributions may be more in the order of 80 percent of available cash flow, with the remaining 20 percent reinvested in replacing reserves and production. Distributions are to be paid monthly based upon quarterly estimates of forward cash flow, annual estimates of capital expenditures and maintenance of conservative debt levels. Quarterly top-ups will be provided as additional cash for distribution is available. A Distribution Reinvestment and Optional Unit Purchase Plan (DRIP) will be available to Canadian Unitholders, providing an opportunity to purchase additional units at a discount to market. The Trust's cash distributions are initially expected to be 30 to 40 percent tax deferred.

OUTLOOK

In summary, we are excited to begin this new era of adding value for Paramount shareholders. In 2003, with the winter capital program completed, the Trust is targeting to maximize distributions. With a base production forecast of 88 MMcfd coupled with estimated natural gas prices averaging \$6.70/Mcf, distributions are expected to be at least \$3.05/unit for 2003. With a state of the art trust structure, an inventory of development opportunities, an experienced technical team and management dedicated to value added growth, we welcome this opportunity and challenge to establish PFT as one of the premier investment opportunities in the Canadian oil patch. Off like a herd of turtles, but slow and steady wins the race.

Sue Riddell Rose

Sue Riddell Rose
President & Chief Operating Officer



MECHANICS OF TRUST CREATION

The Trust was formed through a series of transactions essentially as described below:

On February 3, 2003:

- (1) POT acquired the Legend property from PRL for an \$81 million promissory note;
- (2) PET issued approximately 9.9 million Trust Units to PRL; and
- (3) PRL declared a dividend to be paid to its shareholders on February 12, 2003 of these Trust Units, at 1 Unit per 6,071646 shares, valued at \$5.15 per Trust Unit, or approximately \$0.85 per Paramount Common Share.

On February 17, 2003:

- (4) PET issued 3 Rights per Trust Unit exercisable @ \$5.05 per Right.

On March 11, 2003:

- (5) With proceeds of the rights offering of approximately \$150 million, which was successfully closed with full subscription on March 10, 2003, plus bank debt, POT purchased from PRL the majority of PRL's remaining Northeast Alberta natural gas assets for \$220 million. The effective date of the property transactions was July 1, 2002, which, after adjustment for primarily net cash flow and interest, resulted in the Trust assuming \$70 million in bank debt.

THE TEAM

PRL's Summit transaction provided many of the items required to effect the initial public offering of PET which would otherwise have been an incremental cost, including accounting systems, office space and furniture, land records system, and computer systems and software. The team assembled both in the field and office, brings continuation on the operations and marketing side, as this effectively the same team that has worked the Northeast Alberta assets for the past three to five years, with some expertise stretching as far back as 20 years. The administrative, accounting and land functions have been assumed by ex-Summit staff for the most part, beginning with the migration of data to PEOC's systems in early July, in accordance with the effective date of the asset transactions. Finally, an extremely competent independent Board of Directors has been assembled which will ensure good corporate governance practices, offering both valuable experience in the oil and gas sector as well as extensive royalty trust experience. As has always been the case with PRL, the high management ownership of PET, in the order of 49 percent, dictates that management is extremely well aligned with unitholders.

OPERATIONS

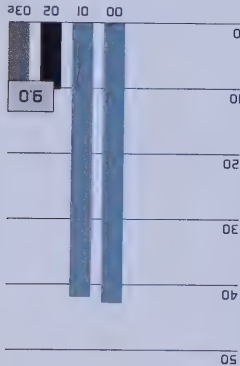
Right off the mark, PET is amongst the top ten energy trusts with respect to production and reserves, and the only trust levered 100% to natural gas. Although our asset base will likely continue to be unique relative to our peers, our operating practices will be conservative, targeting stable distributions for unitholders through conservative and prudent management of capital and operating costs, debt and natural gas price volatility. It is the intention of the Trust to grow through prudent investment; optimizing our current asset base through low risk exploitation, pursuing value-added corporate and property acquisitions for both maintenance production and growth, and actively managing our the financial flexibility to pursue opportunities as they materialize.

The Trust inherited an extremely focused Northeast Alberta asset base, characterized by long production histories, a predictable production profile, high field netbacks, minimal ongoing capital

RESULTS

Net Capital Expenditures

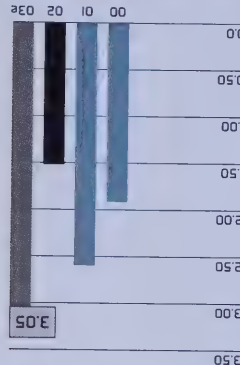
(\$ millions)



RESULTS

Portfolio Distributions per Unit

(\$/Unit)



Letter to Unitholders

On May 12, 2002, Paramount Resources Ltd. (PRL) announced its intention to create a new natural gas focused royalty trust. The mature, net cash generating, producing properties in Northeast Alberta to be transferred to the trust were considered to be suitable for a trust and management believed the transaction would be financially beneficial to shareholders of PRL. The press release or the Trust) contained a remarkably close account of the events which eventually transpired to create the Trust, despite extraordinary and unanticipated delays in the regulatory process related to the required F-1 U.S. Registration Statement. Delays in the process were significant, but persistence resulted in completion of the required transactions to launch Paramount Energy Trust into what is proving to be the start of the next North American natural gas low supply, high demand price cycle.

BUSINESS PURPOSE

The primary business purpose for creating the Trust was to divide Paramount Resources' assets, operations and management expertise into two entities that would maximize value for its shareholders:

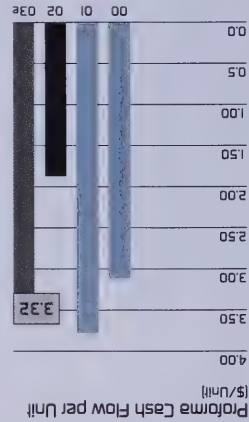
- (1) Paramount Resources continues to concentrate on exploration, development and exploitation of properties with a higher risk/ reward profile; and
- (2) Paramount Energy Trust provides a vehicle to eliminate the layer of corporate income tax attributable to the mature production income associated with Paramount's proven low risk northeast Alberta natural gas properties, by flowing out net cash flow in the form of distributions directly to its unitholders. This consideration was particularly important given the substantial amount of taxes PRL would be incurring and which would negatively impact its financial flexibility and growth plans as cash available for capital expenditures would be reduced.

At the same time, the Trust has provided a tax-effective vehicle to become more competitive in the acquisitions market and capitalize on the enhanced access to equity markets and the lower cost of capital currently enjoyed by the oil and gas royalty trust sector.

TRUST STRUCTURE

PELT was built with a state of the art trust structure. The structure required the formation of three new entities; Paramount Energy Trust (PET), Paramount Operating Trust (POT) and its administrator and trustee, Paramount Energy Operating Corp. (PEOC). PET was established for the purpose of issuing Trust Units and acquiring and holding royalties and other investments including the entire beneficial interest in POT and the POT Royalty. PET effectively finances the operations of POT. PET distributes cash to its Unitholders, which will initially be comprised of royalty and interest income PET receives from POT and from Alberta Royalty Tax Credit, if any, less expenses, capital expenditures and debt repayments. POT's business is acquiring, developing, exploiting, owning and disposing of oil and natural gas properties. Under the terms of the POT Trust Indenture, PEOC is the trustee of POT. Unlike many conventional royalty trusts, PET does not have an external management company. The day-to-day management of our business is carried out by the wholly-owned PEOC, rather than a third party. All of the issued and outstanding shares of PEOC are beneficially held by PET. As trustee of POT, PEOC holds legal title to the assets and properties of POT on behalf of, and for the benefit of, POT and retains employees to administer, manage and operate the oil and gas business of POT. In addition, PEOC carries out the significant management, administrative and governance functions with respect to PET. The Trust and its unitholders will therefore not incur any management fees and expenses like those that would be charged by an external management company.

RESULTS



Forecast 2003
return on
Paramount Energy
Trust Rights
offering over
200%

SUE RIDDELL ROSE
PRESIDENT & CHIEF
OPERATING OFFICER

CLAY RIDDELL
CHAIRMAN OF
THE BOARD & CHIEF
EXECUTIVE OFFICER



2002 Proforma Financial Highlights

(1)(2)

Financial			
(\$ thousands except per share amounts)			
Year Ended December 31	2002	2001	% Change
Gross Revenue	123,739	228,283	(46%)
Cash Flow ⁽³⁾			
From operations	74,191	149,652	(50%)
Per Trust Unit - basic ⁽⁴⁾	1.87	3.78	(51%)
- diluted ⁽⁵⁾	1.85	3.74	(51%)
Earnings ⁽⁶⁾			
Net earnings	n/a	n/a	-
Per share - basic ⁽⁴⁾	n/a	n/a	-
- diluted ⁽⁵⁾	n/a	n/a	-
Capital expenditures			
Exploration and development	10,227	41,863	(76%)
Net capital expenditures	10,227	41,863	(76%)
Total Assets ⁽⁶⁾			
Net Debt ⁽⁶⁾	n/a	n/a	-
Shareholders' Equity ⁽⁶⁾	n/a	n/a	-
Weighted Average Trust Units Outstanding (thousands) ⁽⁴⁾	39,639	39,639	-
Trust Units Outstanding at Year End (thousands) ⁽⁴⁾	39,639	39,639	-
Diluted Trust Units Outstanding at Year End (thousands) ⁽⁴⁾	40,642	40,642	-
Operating			
Production			
Natural gas (MMcfd)	94.8	102.7	(8%)
Crude oil and liquids (Bbl/d) @ 10:1	94.8	102.7	(8%)
Total Production (MMcfd/d) @ 10:1	94.8	102.7	(8%)
Total Production (BOE/d) @ 6:1	15,807	17,117	(8%)
Average Prices			
Natural gas (pre-hedge) (\$/Mcf)	3.57	6.09	(41%)
Natural gas (\$/Mcf)	3.57	6.09	(41%)
Crude oil and liquids (\$/Bbl)	n/a	n/a	-
Reserves (proved and probable)			
Natural gas (Bcf)	203.6	237.0	(14%)
Crude oil and liquids (MBbl)	-	-	-
Estimated present worth value before tax discounted @ 10%	-	-	-
Proved (\$MM)	313	325	(4%)
Proved and probable (\$MM)	372	392	(5%)
Land (thousands of acres)	1,200	n/a	-
Total net land holdings	341	n/a	-
Net undeveloped land holdings			
Drilling Activity (gross)	18	38	(53%)
Gas	-	-	-
Oil	-	-	-
Other	-	-	-
D&A	2	3	(33%)
Total wells	20	41	(51%)
Success rate	90%	93%	(3%)
(1) Throughout this report, unless otherwise stated, crude oil and liquids volumes have been converted to natural gas (Mcf) on the basis of one barrel of oil equals 10 Mcf of gas.			
(2) Throughout this report all figures are pro forma for the assets acquired by Paramount Operating Trust from Paramount Resources Ltd. These figures are inclusive in the results of Paramount Resources Ltd. for the periods shown, as the acquisition by Paramount Operating Trust closed in the first quarter of 2003.			
(3) Amount represents net operating income defined as revenue less royalties and operating costs.			
(4) The Trust Units indicated are pro forma. Actual units were issued by Paramount Energy Trust in the first quarter of 2003.			
(5) There are 1,003,000 unit incentive rights issued and outstanding.			
(6) Not allocated in preparation of proforma financial statements.			

Paramount Energy Trust (PET) is a natural gas focused Canadian energy royalty trust which commenced operations in February 2003 with the acquisition of the vast majority of Paramount Resources Ltd.'s producing shallow natural gas properties in Northeast Alberta. Trust units were listed on the Toronto Stock Exchange on February 7, 2003 under the symbol PMT.UN.

PET operates over 94 percent of its extremely focused asset base which is characterized by long production histories, a predictable production profile, high field netbacks, minimal ongoing capital requirements and strategic infrastructure ownership. PET's operating practices are conservative, targeting stable distributions and premium after-tax returns at an acceptable risk for all stakeholders through attentive management of capital programs, operating costs, debt and natural gas price volatility. PET will grow through prudent investment, optimizing the value of its asset base through low risk exploitation, pursuing value-added corporate and property acquisitions for both maintenance production and growth, and proactively managing its extensive undeveloped land base.

PET features a state of the art trust structure with high management ownership and no external management fees or contracts, thereby directly aligning the management of the Trust with Unitholders and sharing the objective to receive superior returns from our investment.

Paramount Energy Trust is Canada's only 100 percent natural gas royalty trust.



PARAMOUNT
ENERGY
TRUST